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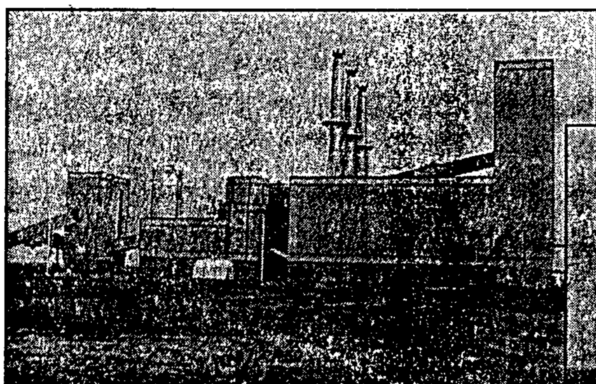
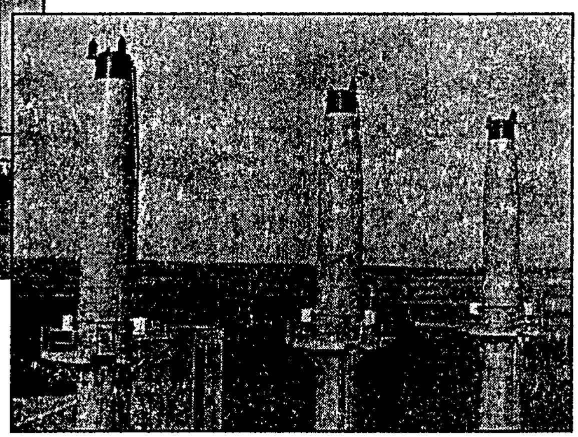
NOx Evaluation of Coal-Fired Heat Plant at Malmstrom AFB, MT

John Salley
Charles Schmidt
Martin Savoie
Eric Johnson





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The Malmstrom Air Force Base (MAFB), MT Coal-Fired Heat Plant (CFHP) is designed to fire natural gas or coal. The State of Montana requires that nitrogen oxides (NOx) levels be maintained below the level of 0.50 lb/MMBtu of coal. This study evaluated the Malmstrom AFB CFHP to determine operational and equipment changes to ensure that the CFHP can operate under a wide range of conditions using either coal, or a mix of gas and coal as fuel. Several enhancements were recommended to the CFHP to improve combustion efficiency and air emissions, including: improved coal specifications, advanced monitoring systems, combustion air heater modifications, variable speed drives, and operator training.

Foreword

This study was conducted for Malmstrom AFB, MT under Operations and Maintenance, Air Force (OMAF) Project Order 99-001, Work Unit VF9, "NOx Evaluation at Malmstrom AFB Coal-Fired Plant." The technical monitor was David Heckler, 341CES/CEV.

The work was performed by the Energy Branch (CF-E), of the Facilities Division (CF), U.S. Army Construction Engineering Research Laboratory (CERL). The CERL principal investigator was Martin J. Savoie. Larry M. Windingland is Chief, CEERD-CF-E, and L. Michael Golish is Chief, CEERD-CF. The CERL technical editor was William J. Wolfe, Information Technology Laboratory.

The Director of CERL is Dr. Michael J. O'Connor.

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1 Introduction

Background

The Malmstrom Air Force Base (MAFB), MT Coal-Fired Heat Plant (CFHP) is designed to fire natural gas or subbituminous coal with a maximum sulfur content of 1 percent. The plant contains three large high temperature water generators (HTWGs) to provide high temperature hot water (HTHW) heat to the entire base. HTWG No. 1 can burn coal or natural gas. HTWG No. 2 was converted to burn natural gas only. HTWG No. 3 can only burn coal. The spreader-stoker coal-fired HTWGs have an input capacity of 106 million British thermal units per hour (MMBtu/hr) and an output capacity of 85 MMBtu/hr. When natural gas is burned, the maximum output capacity approximates 30 MMBtu/hr per HTWG, for a total of 60 MMBtu/hr for two units. During the winter months, one coal-fired HTWG normally provides ample heat for the entire base. The other generators serve as standby units.

In the spring and autumn, natural gas has been used to heat the entire base, although it is questionable whether two HTWGs fired on gas operating at capacity (60 MMBtu/hr) can provide adequate heat for the entire base during extremely cold periods. The plant has to be fired on coal when the demand exceeds the natural gas capability of 60 MMBtu/hr since only two HTWGs can be fired on natural gas. The State of Montana requires that nitrogen oxide (NOx) levels be maintained below the level of 0.50 lb/MMBtu of coal. This research recommends several enhancements to heating plants to improve combustion efficiency and air emissions. These enhancements include: improved coal specifications, advanced monitoring systems, combustion air heater modifications, variable speed drives (VSDs), and operator training. Figure 1 shows the air/flue gas flow for a coal-fired HTWG.

Objectives

The objective of this investigation was to evaluate the Malmstrom AFB CFHP to determine operational and equipment changes to ensure that the CFHP can operate under a wide range of conditions while maintaining NOx emission levels below the allowable limits set by Montana State regulations. Plant operators must be able to quickly diagnose and prevent unstable combustion conditions that result in increased NOx emissions.

Approach

1. *Artificial Heat Load.* Because system tests and evaluations were conducted late in the heating season, the heat load or demand on the CFHP would not be at levels required for official permit testing. It was therefore necessary to build an artificial load to provide an evaluation near actual test conditions. This ability to create artificial loads would also allow the HTWGs to be tested over their full operating range. Three methods were used to build artificial loads: distribution temperature sag, use offline units as radiators, and open hangar doors.

2. *Conduct Emissions Testing.* This work was done by a team of experts consisting of CERL researchers, consultants from Schmidt and Associates, Inc. (SAI), and MAFB staff. The team tested HTWG Nos. 1 and 3 while burning coal to determine NOx levels over a full range of operating capacity. The following parameters were measured: flue gas temperature, flue gas oxygen (O_2) content, flue gas carbon monoxide (CO) content, flue gas NOx, and flue gas sulfur dioxide (SO_2) content at both the air preheater inlet and the spray dryer absorber (SDA) inlet. In addition, a velocity traverse was conducted at the SDA inlet to determine flue gas flow. Coal samples were taken at the feeders for proximate and ultimate analysis. MAFB plant personnel operated the plant during the tests and assisted with combustion and emission tests.

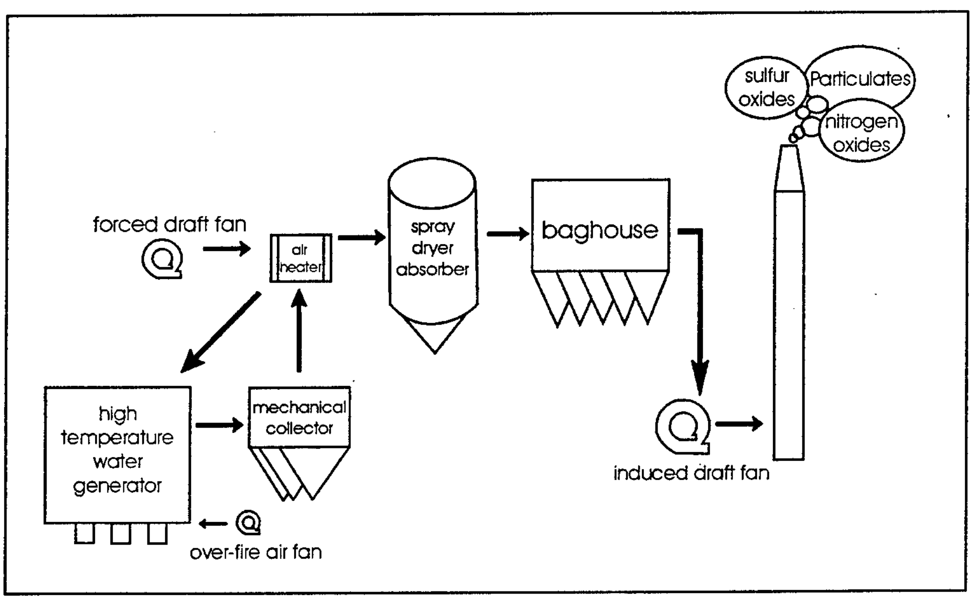

Figure 1. Air/flue gas flow: coal-fired HTWG.

3. *Co-Fire Natural Gas and Coal.* The team performed operational tests on HTWG No. 1 to determine the feasibility of co-firing natural gas and coal. Tests included start-up of stoker grate, feeders, over-fire air (OFA), and stoker furnace draft and forced draft fans, while controls were set to burn natural gas.

4. *Evaluate Existing Coal System Equipment.* The team evaluated existing coal equipment to determine changes required to reduce NOx and to improve plant efficiency. The team investigated coal quality parameters, coal handling procedures and equipment, combustion air and flue gas flow, and combustion air heater operation.

5. *Evaluate Coal System Operation and Maintenance (O&M).* The team evaluated plant O&M procedures for firing on coal. The team focused on stoker and furnace maintenance, controls, and instrumentation.

6. *Fuel and NOx Control Alternatives.* The team provided preliminary cost estimates for all the different options described above. Preliminary cost estimates were prepared for labor, material, and equipment for complete installation of each process described above. The team provided a cost effective analysis including all labor, material, maintenance, equipment, operational costs, and environmental compliance costs for the following options:
   - existing CHP operation on coal without NOx reduction equipment
   - CHP operation on coal with new NOx reduction equipment
   - CHP operation on 100 percent natural gas.

Mode of Technology Transfer

At MAFB's discretion, CERL will provide lessons learned from this effort to other stoker CFHPs to support both Federal and private sector goals to improve air quality.

Units of Weight and Measure

U.S. standard units of measure are used throughout this report. A table of conversion factors for Standard International (SI) units is provided below.

SI conversion factors		
1 in.	=	2.54 cm
1 ft	=	0.305 m
1 yd	=	0.9144 m
1 sq in.	=	6.452 cm^2
1 sq ft	=	0.093 m^2
1 sq yd	=	0.836 m^2
1 cu in.	=	16.39 cm^3
1 cu ft	=	0.028 m^3
1 cu yd	=	0.764 m^3
1 gal	=	3.78 L
1 lb	=	0.453 kg
1 psi	=	6.89 kPa
°F	=	(°C x 1.8) + 32

2 Procedures to Create Artificial Heat Load

Because system tests and evaluations were conducted late in the heating season, the heat load or demand on the CFHP would not be at levels required for official permit testing. It was therefore necessary to build an artificial load to provide an evaluation near actual test conditions. This ability to create artificial loads would also allow the HTWGs to be tested over their full operating range. Three methods were used to build artificial loads.

Distribution Temperature Sag

The distribution system normally operates at 390 °F. The distribution return temperature was allowed to drop or sag to 290 °F. This temperature was held until a test was to be performed, which resulted in about 14 MMBtu/hr increase in load. However, at 290 °F the hospital system temperature was too low to provide steam at the required temperature. It is likely the hospital could not make steam at 90 psig when the system temperature was allowed to sag because the tube bundle in the converter is too small. When the outlet temperature drops below 375 °F, it is not unusual for the hospital to notify the CFHP that adequate steam pressure cannot be maintained.

MAFB personnel started hospital back-up boilers, which dropped system demand. With additional trials, the lowest return temperature that would still meet hospital requirements could be determined.

Use Off-Line Units as Radiators

While HTWG No. 3 was operating, MAFB personnel circulated water in HTWG Nos. 1 and 2 and ran the system fans to exhaust the warmed air through the stacks. This operation tripped induced draft (ID) fan motors during circulation of water in HTWG Nos. 1 and 2. The “trip” occurred because the dampers were in an open position. The fans were moving cold, dense air instead of hot, less dense flue gas, which required more horsepower than the fan motor rating. After adjusting the airflow, a load of about 8 MMBtu/hr was sustainable.

Open Hangar Doors

Hangar doors were opened to force the heating system to operate continuously. The heat exchangers were set on manual to provide maximum output. The apparent increase in load was only about 0.5 MMBtu/hr. Based on the number and ratings of heat exchangers in the hangars, the load increase should have been in about 2 to 4 MMBtu/hr. However, the lost loads and increasing outside temperature made it difficult to quantify the load increase.

Dump Steam/Water From HTHW Converters and Heat Exchangers

This fourth method was not tested. It was determined that, if steam/water were dumped from the HTHW converters and heat exchangers while the distribution system temperature was at low temperature (290 °F for sag), the buildings would not achieve a comfortable temperature.

After completion of the three tested operations, the load increase ranged from 24.4 to 32 MMBtu/hr.

3 NOx Test Results

During the 1-11 March 1999 site visit, CERL and SAI conducted flue gas analysis at the mechanical dust collector (MDC) outlet and the SDA inlet to evaluate the effect of flue gas oxygen content on NOx emissions over the HTWG operating range. The coal feed rate was measured from data taken from the coal scales and printouts of the Bailey INFI 90 control screens were made. HTWG heat output was calculated from the coal scale heat input and the American Society of Mechanical Engineers (ASME) Power Test Code (PTC) 4.1, Abbreviated Efficiency Test, Heat Loss Method (ASME PTC 4.1). The field-test data and calculations are included in Appendix A.

Flue gas analysis was conducted at the four ports in the vertical breeching between the MDC outlet and air preheater inlet and also at the four ports in the horizontal breeching between the air preheater outlet and SDA inlet. Flue gas analysis at the air preheater inlet included temperature, O_2 by dry volume, CO by dry volume, combustibles by dry volume measured as methane, NOx by dry volume, and SO_2 by dry volume. Flue gas analysis at the SDA inlet included the same parameters as the air preheater inlet with the addition of a velocity traverse to determine flue gas flow. The velocity traverse flue gas flow was compared to flue gas flow calculated from coal scale fuel flow and ASME PTC 4.1 combustion efficiency. The HTWGs were held under fairly steady state operating conditions during the approximately 45-minute data recording. Printouts were made every 15 minutes of HTWG operation recorded by the Bailey INFI 90 system.

The formation of NOx increases during a combination of higher furnace temperatures and higher flue gas O_2 contents or excess air. By reducing the excess air in the furnace, the furnace temperature and NOx formation will be reduced.

The first test was conducted on 5 March on HTWG No. 3 at an INFI 90 Btu meter load of 64.03 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 6.44 percent O_2 by dry volume, 212 ppm of CO, 442 °F flue gas temperature, and 353 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 7.21 percent O_2 by dry volume and 289 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 82.15 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 77.09 MMBtu/hr. NOx emissions were calculated to be 0.480 lb/MMBtu.

Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 4,634 lb/hr or 4.3 percent of the total flow at the SDA inlet.

Test Run No. 2 was conducted on 5 March on HTWG No. 3 at an INFI 90 Btu meter load of 67.48 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 4.74 percent O_2 by dry volume, 509 ppm CO, 441 °F flue gas temperature, and 306 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 5.55 percent O_2 by dry volume and 290 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 82.53 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 81.26 MMBtu/hr. NOx emissions were calculated to be 0.416 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 4,699 lb/hr, or 4.6 percent of the total flow at the SDA inlet.

Test Run No. 3 was conducted on 5 March on HTWG No. 3 at an INFI 90 Btu meter load of 55.21 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 5.81 percent O_2 by dry volume, 45 ppm CO, 409 °F flue gas temperature, and 334 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 6.58 percent O_2 by dry volume and 276 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 83.87 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 64.74 MMBtu/hr. NOx emissions were calculated to be 0.454 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 4,248 lb/hr, or 4.9 percent of the total flow at the SDA inlet.

Test Run No. 4 was conducted on 5 March on HTWG No. 3 during normal plant operation at an INFI 90 Btu meter load of 45.11 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 8.20 percent O_2 by dry volume, 28 ppm CO, 402 °F flue gas temperature, and 408 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 8.64 percent O_2 by dry volume and 268 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 83.59 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 52.49 MMBtu/hr. NOx emissions were calculated to be 0.555 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 3,223 lb/hr, or 4.0 percent of the total flow at the SDA inlet.

Test Run No. 5 was conducted on 5 March on HTWG No. 3 after reducing the flue gas oxygen content at an INFI 90 Btu meter load of 46.41 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 5.39 percent O_2 by dry volume, 101 ppm CO, 378 °F flue gas temperature, and 297 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 6.30 percent O_2 by dry volume and 261 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 84.78 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 54.37 MMBtu/hr. NOx emissions were calculated to be 0.404 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 3,484 lb/hr or 4.9 percent of the total flow at the SDA inlet.

Test Run No. 6 was conducted on 9 March on HTWG No. 1 at an INFI 90 Btu meter load of 63.18 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 5.81 percent O_2 by dry volume, 234 ppm CO, 407 °F flue gas temperature, and 327 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 11.8 percent O_2 by dry volume and 279 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 84.29 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 63.01 MMBtu/hr. NOx emissions were calculated to be 0.444 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 47,533 lb/hr or 37.3 percent of the total flow at the SDA inlet.

Test Run No. 7 was conducted on 9 March on HTWG No. 1 at an INFI 90 Btu meter load of 60.03 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 6.00 percent O_2 by dry volume, 192 ppm CO, 406 °F flue gas temperature, and 339 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 9.97 percent O_2 by dry volume and 281 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 84.42 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 61.22 MMBtu/hr. NOx emissions were calculated to be 0.461 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 26,580 lb/hr or 25.5 percent of the total flow at the SDA inlet.

Test Run No. 8 was conducted on 10 March on HTWG No. 1 at an INFI 90 Btu meter load of 40.56 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 7.85 percent O_2 by dry volume, 50 ppm CO, 358 °F flue gas temperature, and 368 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 9.21 percent O_2 by dry volume and 250 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 84.10 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 43.07 MMBtu/hr. NOx emissions were calculated to be 0.500 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 6,704 lb/hr, or 9.7 percent of the total flow at the SDA inlet.

Test Run No. 9 was conducted on 10 March on HTWG No. 1 at an INFI 90 Btu meter load of 25.05 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 9.44 percent O_2 by dry volume, 103 ppm CO, 338 °F flue gas temperature, and 391 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 10.68 percent O_2 by dry volume and 242 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 83.62 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 28.96 MMBtu/hr. NOx emissions were calculated to be 0.532 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 4,849 lb/hr, or 9.1 percent of the total flow at the SDA inlet.

Test Run No. 10 was conducted on 10 March on HTWG No. 1 at an INFI 90 Btu meter load of 30.36 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 8.58 percent O_2 by dry volume, 74 ppm CO, 343 °F flue gas temperature, and 365 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 9.83 percent O_2 by dry volume and 247 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 84.27 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 34.96 MMBtu/hr. NOx emissions were calculated to be 0.497 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 5,847 lb/hr, or 9.8 percent of the total flow at the SDA inlet.

Test Run No. 11 was conducted on 11 March on HTWG No. 1 at an INFI 90 Btu meter load of 65.73 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 5.85 percent O_2 by dry volume, 1,568 ppm CO, 415 °F flue gas temperature, and 364 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 6.60 percent O_2 by dry volume and 283 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 83.42 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 70.81 MMBtu/hr. NOx emissions were calculated to be 0.495 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 6,663 lb/hr, or 7.1 percent of the total flow at the SDA inlet.

Test Run No. 12 was conducted on 11 March on HTWG No. 1 at an INFI 90 Btu meter load of 29.87 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 7.23 percent O_2 by dry volume, 131 ppm CO, 343 °F flue gas temperature, and 295 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 8.40 percent O_2 by dry volume and 239 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 84.80 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 31.99 MMBtu/hr. NOx emissions were calculated to be 0.402 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 3,624 lb/hr, or 7.5 percent of the total flow at the SDA inlet.

Test Run No. 13 was conducted on 11 March on HTWG No. 1 at an INFI 90 Btu meter load of 18.90 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 7.39 percent O_2 by dry volume, 253 ppm CO, 326 °F flue gas temperature, and 257 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 10.06 percent O_2 by dry volume and 222 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 84.28 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 23.73 MMBtu/hr. NOx emissions were calculated to be 0.349 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 7,313 lb/hr, or 17.7 percent of the total flow at the SDA inlet.

Test Run No. 14 was conducted on 11 March on HTWG No. 1 at an INFI 90 Btu meter load of 43.45 MMBtu/hr heat output. Data recorded at the MDC outlet averaged 5.83 percent O_2 by dry volume, 217 ppm CO, 368 °F flue gas temperature, and 303 ppm NOx corrected to 3 percent O_2. Data recorded at the SDA inlet averaged 7.80 percent O_2 by dry volume and 253 °F flue gas temperature. Combustion efficiency calculated according to the ASME PTC 4.1 was 84.50 percent. Heat output calculated from the efficiency and coal flow from the coal scale was 45.58 MMBtu/hr. NOx emissions were calculated to be 0.413 lb/MMBtu. Air infiltration across the air heater between the MDC outlet and SDA inlet was calculated to be 7,745 lb/hr, or 11.8 percent of the total flow at the SDA inlet.

Control of HTWG flue gas O_2 or excess air, as well as even coal combustion across the grate, are critical in controlling NOx emissions. At 24 MMBtu/hr heat output, the flue gas O_2 content was 7.39 percent by dry volume or 6.84 percent by wet volume. CO was 253 ppm and NOx emissions were 0.349 lb/MMBtu. At 29 MMBtu/hr heat output, the flue gas O_2 content was 9.44 percent by dry volume, or 8.84 percent by wet volume. CO was 103 ppm and NOx emissions were 0.532 lb/MMBtu. The CO at 29 Btu/hr load of 103 ppm is indicative of good coal combustion as compared to the CO of 253 ppm at 24 MMBtu/hr load, which had less complete combustion. The O_2 content increased from 7.39 percent to 9.44 percent and the resulting NOx emissions increased from 0.349 lb/MMBtu to 0.532 lb/MMBtu.

The test at 52 MMBtu/hr was conducted under normal plant operating conditions. Flue gas O_2 content was 8.05 percent by dry volume or 7.48 percent by wet volume. CO averaged 42 ppm indicating very good combustion and an even fuel bed. However, the NOx emissions averaged 0.534 lb/MMBtu. The flue gas O_2 was lowered to reduce NOx emissions and another test was conducted at 54 MMBtu/hr heat output. The average flue gas O_2 decreased to 5.39 percent by dry volume or 4.95 percent by wet volume and the CO increased to 113 ppm. NOx emissions were reduced to 0.404 lb/MMBtu.

The test at 71 MMBtu/hr heat output was conducted during a time when clinkers were forming on the grate and incomplete combustion was occurring. The flue gas O_2 content was 5.85 percent by dry volume or 5.38 percent by wet volume, which is typical for this HTWG load. However, the CO averaged 1,568 ppm, indicating uneven fuel distribution and combustion, and the NOx emissions increased to 0.495 lb/MMBtu (Figures 2 and 3).

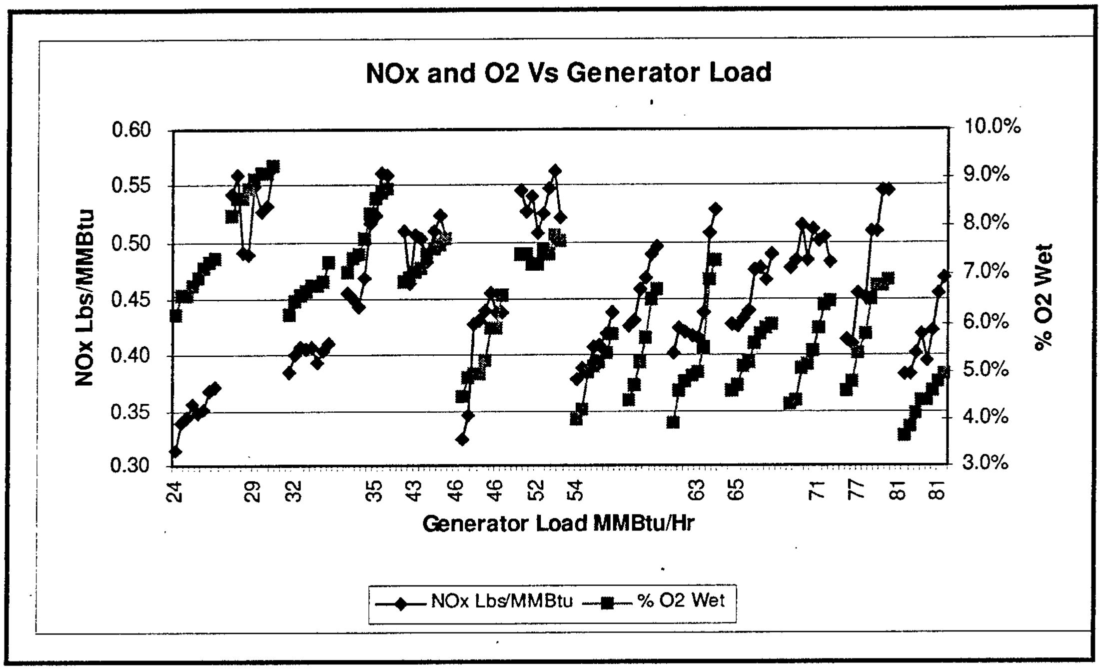

Figure 2. NOx and O_2 versus generator load.

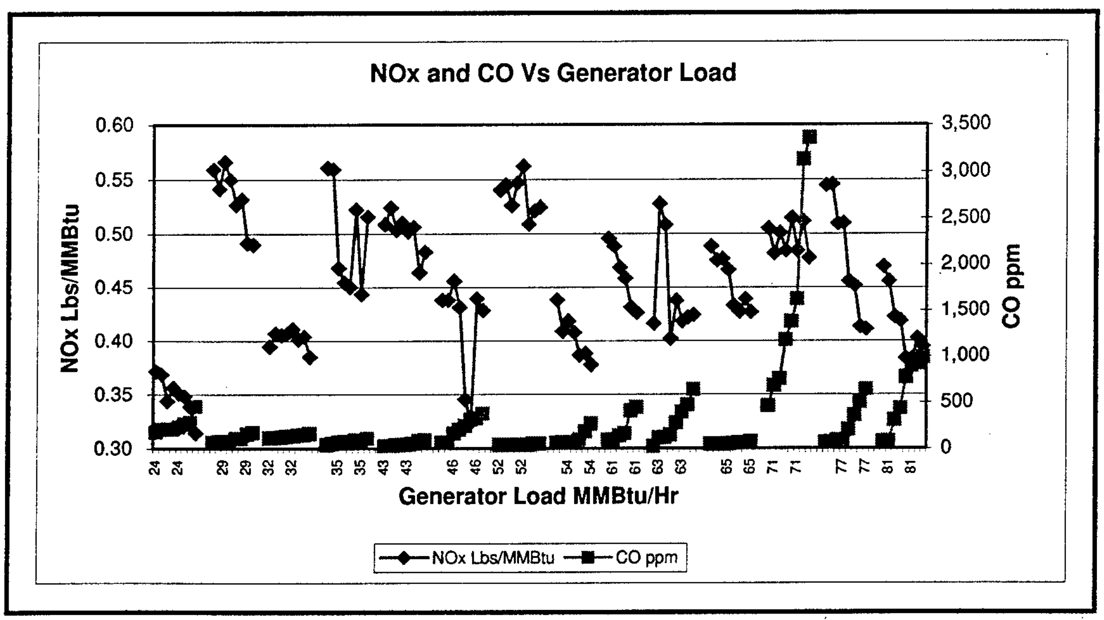

Figure 3. NOx and CO versus generator load.

There was a variation in both flue gas oxygen content and flue gas temperature across the air heater inlet breeching, which relates directly to the condition of the fuel bed in the furnace. A thin area in the fuel bed allows more air to flow through, which increases the excess oxygen and reduces the flue gas temperature above that area. As the oxygen contents and the flue gas temperatures became more uniform, it indicated more even coal combustion across the grate (Figure 4).

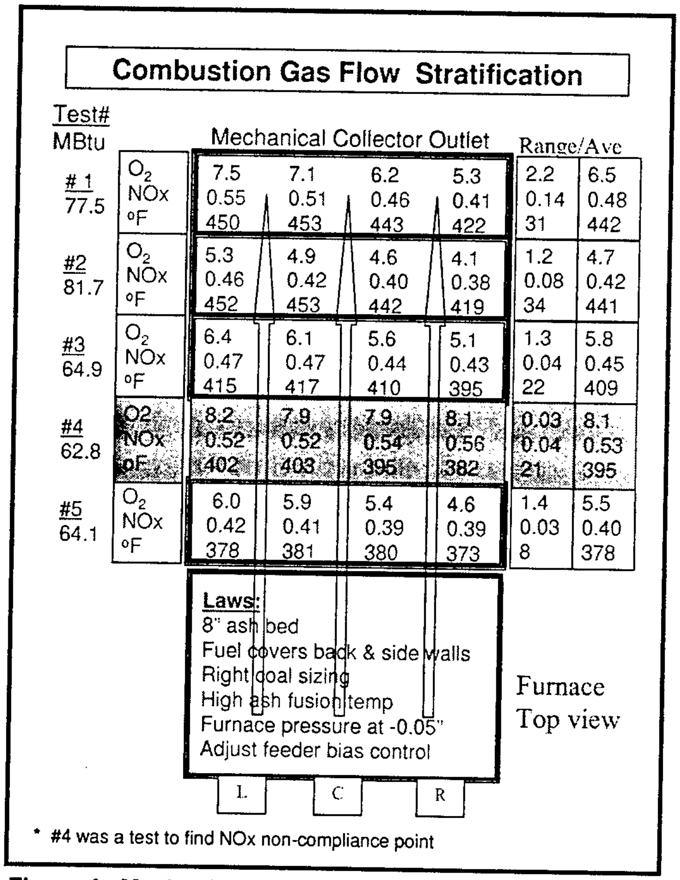

Figure 4. Mechanical collector inlet.

4 Co-Firing Tests

The team performed operational tests on HTWG No. 1 to determine the feasibility of co-firing natural gas and coal. Tests included start-up of stoker grate, feeders, OFA, and stoker furnace draft and forced draft (FD) fans, while controls were set to burn natural gas.

Existing Combustion Controls/System Constraints

- The combustion controls are currently configured so that only coal or natural gas can be fired. The reasons for this are:
  1. Coal heat input can equal 130 x 106 Btu/hr heat output
  2. Natural gas input can equal 30 x 106 Btu/hr heat output
  3. The maximum rating of boilers (HTHW generators) is 130 x 106 Btu/hr
  4. If both fuels are fired at 100 percent capacity of fuel, the heat output could reach 160 x 106 Btu/hr, which would damage the units.
- The small ID fan (used with natural gas) is interlocked with the small FD fan and burner.
- The large ID fans and the large FD fan for coal combustion are interlocked.
- The small ID fan and burner cannot be operated at the same time as large ID fan and coal FD fan.
- The large ID fan and coal FD fan cannot be operated at the same time as the small ID fan and burner.

Co-firing Trial

A trial co-firing was accomplished for a short time with the following procedure:

- The furnace was cold; there was no heat input to boiler.
  1. The spreader coal feeders were manually started to put 1 to 1-1/2 in. of coal on the grates. The purpose of this was to protect the grates from future natural gas flame radiation.

2. The large FD fan damper was manually opened to 100 percent open with the fan off. This is to allow the furnace static pressure at –0.15 to cause a small amount of cooling air through grates when the burner is started.

- The small ID fan was placed in automatic operation with the burner and burner FD fan. This step:

1. Allowed normal pre-purge of both fans.
2. Allowed normal low fire light off of natural gas igniter.
3. Allowed normal low fire light off of natural gas main fuel valve.
4. Placed the natural gas burner in a manual position of 30 percent fuel input.
   — Held the flame to 30 percent to 40 percent of normal flame length.
   — Keep the flame away from coal feeders.

- Startup on coal.

1. The large ID fan for coal was manually started.
   — The small ID fan (natural gas) inlet dampers were moved to a closed position, but the small ID fan must still operate to hold the flue gas switch at the small ID fan under negative pressure.
2. The coal ID fan damper was slowly opened (manually) to obtain a furnace condition of –0.30 in. of water.
3. The coal would not ignite from the burner flame, so No. 2 oil rags were placed on top of coal. The rags were ignited before placing them on coal. The coal was dry and hot and ignited rapidly.
4. The large FD fan damper was closed to minimum position and the fan was manually started.
5. The large FD fan damper had to be moved by a person because of all the combustion control interlock.

- Co-firing. It was extremely difficult to operate in the hand/manual mode. However, with major changes in the combustion control logic/programming, co-firing would be possible.

5 Equipment Modifications Analysis

Coal Specifications and Handling

New Coal Specification

The MAFB heating plant has burned a wide variety of coal, and the staff has found that many western coals cannot be combusted in efficiently, or in a manner that prevents damage to stoker and furnace equipment. The current coal contains many fines, which appear to have developed during long-term outside storage. This problem is not a result of handling, but an inherent problem with many western coals. As the coal ages in low humidity climates, the lumps tend to fracture into smaller particles. The combination of fine coal particles and low-ash fusion temperatures causes severe clinker formation on the fuel bed. This damages stoker grates, coat generator tubes, and causes excessive airflow through the furnace. Excess air causes NOx levels to increase. Some of the highest NOx readings were obtained when clinkers were noted in the furnace. The following specifications have been developed to prevent clinkering. It should be noted that more ash is desirable to provide a thicker ash bed, which protects the stoker grates and allows more even distribution of primary combustion air.

Table 1. Specifications.

Specification	Min	Max
Moisture	0%	20%
Volatility	33%	47%
Ash	6%	12%
Sulfur	0%	1%
AST H=W (red.)	2,440 °F	n/a
Na_2O+K_2O	n/a	3%
Sizing	1 1/4" by 1/4"	
Maximum retained	1 1/4"	5%
Maximum passing	1/4 "	5%

Additional coal handing changes to prevent the generation of fines during coal handling are discussed in the remainder of this section.

Coal Fines and Segregation Control

The system cannot tolerate coal containing 40 percent by weight less than 1/4-in. size. The system can accept coal sizing from 1-1/4 in. to zero, but it cannot tolerate large quantities of fines. The coal feeders also cannot tolerate an inconsistent mix of coal sizes, a problem commonly produced by poor handling and storage of the coal.

The fuel purchaser should ensure that incoming coal does not have more than 10 percent 1/4-in. by zero coal because the process of handling coal creates fines; any higher percent of fines will eventually result in an unacceptable fuel. For example, unloading the coal from the railroad car or truck and placing it in the stockpile generates 5 percent more fines (i.e., a purchase of 10 percent immediately results in 15 percent fines in the stockpile). Moving the stockpile into the bunker generates another 5 percent (i.e., up to 20 percent 1/4-in. by zero fines).

When coal segregation does occur, the coal handler must ensure that the stockpile is re-mixed to a uniform state. Since it is undesirable to have 25 percent 1/4-in. by zero coal at these coal feeders, the coal handler must receive help from the person who reclaims the stockpile. The stockpile front-end loader operator must mix some of coal on the perimeter with some of the fines in the center. A rubber tire front-end loader is the correct type of vehicle to move coal without creating yet more fines. The front-end loader operator should layer the coal while building the coal pile so the coal is segregated no more than necessary.

Splitters Under Coal Bunker Feed Chutes

A useful coal-handling system upgrade is to place splitters under bunker chutes to reduce segregation of fines and bigs. Typically, the coal is discharged down a drag conveyer and dropped into the bunker through three openings that alternate every 2 minutes. When coal is piled in one spot, the large coal rolls to the perimeter and the small (1/4-in. x 0-in.) coal is concentrated in the center, a process that inadvertently sizes the coal into a product unsuitable for the feeders.

The solution to this problem lies in creating more, smaller piles of coal (e.g., 12 smaller piles instead of 3 large ones). More small piles result in less coal segregation and separation of big coal and fine coal (Figures 5 and 6).

Outside Coal Storage

Only enough coal to satisfy emergency fuel requirements should be stored outside. The coal in the coal pile should only be used in the event of coal delivery stoppage. This will require just-in-time delivery of coal. When establishing the emergency fuel requirement, consideration should be given to the availability of natural gas.

Just-in-Time Delivery

It is recommended that coal delivery be changed to just-in-time with the coal immediately placed into the bunker. This will eliminate the generation of fine coal caused by moving the coal to and from the outside storage pile.

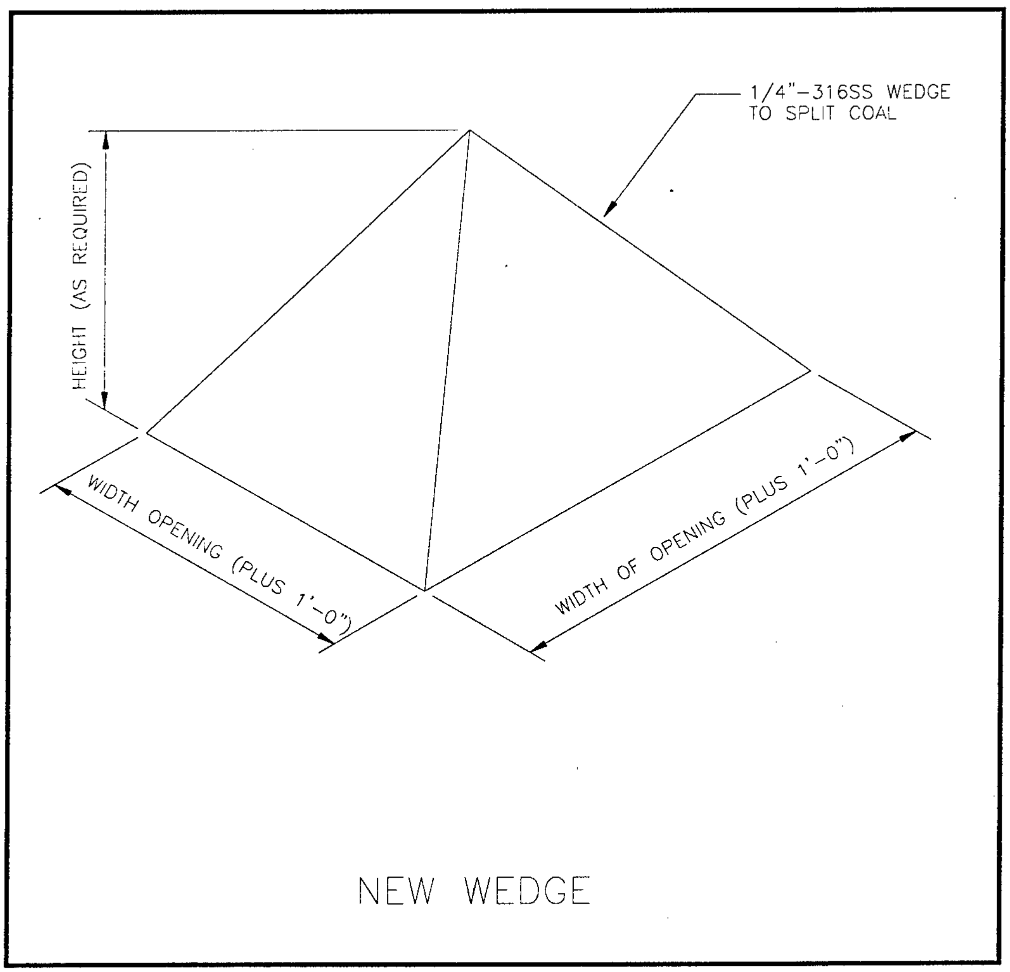

Figure 5. Wedge to split coal.

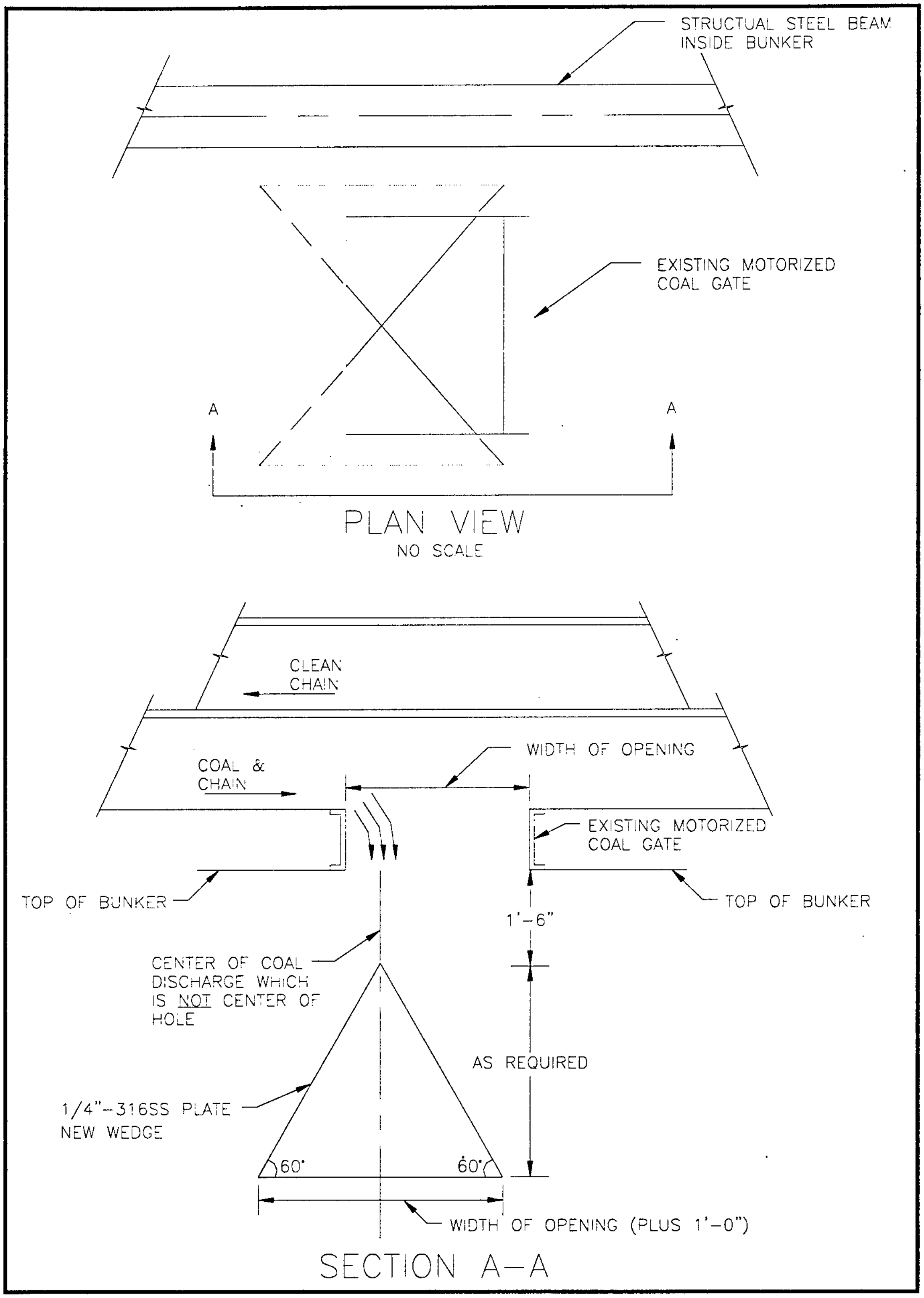

Figure 6. Plan for coal bunker using wedge.

Variable Speed Drives for Forced and Induced Draft Fans

The addition of VSDs for the FD and ID fans will allow better control of furnace draft and the combustion process. Fan dampers have very limited control at low generator loads. The addition of VSDs will allow better operation at lower generator loads and savings in fuel costs. The cost of VSD fans (per boiler) are:

ID Fan – 400 HP			
Motor	$ 25,000	$ 5,000	
VSD (122 °F rated)	70,000	5,000	
Conduit $80/ft. (L/M)	2,400		
Local Disconnect	5,000	5,000	
	$100,000	$17,400	$117,400
FD Fan – 100 HP			
Motor	$ 8,000	$ 5,000	
VSD	40,000	5,000	
	$ 48,000	$10,000	$ 58,000
Subtotal			$175,400
Contractor Overhead and Profit		$ 32,700	
Subtotal			$208,100
Contingency			$ 20,800
Total for one generator			$228,900
Total for two generators			$457,800

Air Heater Modifications

Reduced FD air will reduce effects of low ash fusion temperatures, reduce NOx by reducing ash bed temperatures, and improve SDA operation by allowing inlet temperature to be over 350 °F during the entire HTWG operating range. This modification will also reduce lime consumption because it will be used more efficiently. Higher temperature flue gas entering the SDA would allow more water to be run through the SDA to improve performance. Air heater modifications should include:

- increase SDA inlet temperature to 300 to 350 °F
- reduced NOx causes low SDA temperature
- increase SDA turn-down
- more coal use at low loads
- less SDA maintenance.

By making the SDA capable of greater turn-down, the plant can burn coal instead of natural gas during the spring and autumn. During calendar year 1998, the plant used 7,779.2 tons of coal and 118,599.6 MCF of natural gas at a cost of $1,094,183. By allowing greater turn-down through the use of partial combustion air bypass and higher ash fusion temperature coal, the plant could burn 11,114.8 tons of coal and 23,960 MCF of natural gas at a cost of $879,533, for an annual savings of over $214,000.

1. Air Heater Combustion Air By-Pass for Flue Gas Temperature Control – Cost per Generator

A. FD Fan Discharge Variable Static Pressure versus Heat Input

	Material	Labor	Subtotal
Pressure Transmitter	$ 2,500	$ 500	
Input Card to CPU	4,000	500	
Output Card	4,000	500	
Service Engineer (3 days)		2,500	
	$10,500	$4,000	$14,500

B. Flue Gas Air Heater Discharge Constant Temperature

	Material	Labor	Subtotal
Damper No. 1	$ 10,600	$ 4,000	
Ductwork	1,000	1,200	
Damper No. 2	5,400	4,000	
Ductwork 3' x 3' x 20'	1,000	3,000	
Output Card	4,000		
I/P Converter (2)	600	200	
Service Engineer (3 days)		2,550	
Damper No. 3	6,500	4,000	
Ductwork		1,000	
Flow Indicator	5,000		
I/P Converter (1)	300	100	
Service Engineer (3 days)		2,550	
	$34,400	$22,600	$57,000

C. Service Engineer Travel Expenses $3,750

2. Air Heater Seals To Stop Air Infiltration to Flue Gas Side

	Material	Labor	Subtotal
New Seals	$4,000	$6,000	
Potential for new baskets	24,000	13,000	
	28,000	19,000	$ 47,000
Subtotal for 1 and 2			$122,250
Contractor Overhead and Profit			$ 22,850
Subtotal			$145,100
Contingency			$ 14,500
Total for one generator			$159,600
Total for two generators			$319,200

6 Plant Operation and Maintenance

Stoker and Furnace

The stoker and furnace maintenance practices are outstanding. To achieve an even fuel bed and low excess air, regular maintenance for the stoker and furnace should focus on:

- check and (as needed) renew seals between stoker and pressure parts
- check and adjust the sprocket and chains, and align the grate bar
- adjust feeders.

Controls and Instrumentation

Furnace Draft

The Btu/hr meter at the control panel should be recalibrated. During testing on 5 March, the meter was reading about 50 percent lower than the actual unit output. The Bailey furnace draft should be fixed to control to –0.05 in. The Btu meter, O_2 sensor, and a host of other controls should be regularly checked and recalibrated.

Researchers attempted to adjust proportional, integral, derivative (PID) controller for furnace draft control on HTWG No. 3 to reduce "hunting." The intent was to obtain better control over combustion air to reduce excess air, which would in turn reduce NOx. Some adjustments showed reduced "hunting" for up to 12 minutes, but ultimately the system returned to hunting.

Researchers determined that the furnace draft display at the control panel was reading high. Plant personnel set up an inclined manometer to read furnace pressure directly.

Controls Evaluation

Because of inaccurate sensor readings identified during testing, a specialist was called in (13 and 14 April 1999) to evaluate the HTWG controls and sensors. At this time, there appears to be no immediate safety threat, but major changes need to be made to the configurations stored in the Bailey multi-function processor (MFP) modules to maintain some sense of control. The current configurations will never work properly. Cascade control loops abound, which can confuse the operators and on-site instrument people. There is never any need to use a cascade loop on a boiler. All cascade loops should be removed from the water temperature control as well as from the O_2 Trim controller. Preliminary review shows the rest of the logic in the programming to be reasonable, but it could be assumed that the original programmers had never worked on boiler control previous to the job.

Problems were found with the Furnace Draft control loop. The control was a simple feedback loop PID control, with the provision for feedforward from the FD loop. The loop could only be put in automatic after detuning the controller. The problems encountered were mostly mechanical. There appeared to be too much draft caused by what appeared to be too much ID fan. Installing a VSD on the fan drive motor will help a great deal. In conjunction with the VSD, adjustments can be made to the linkage from the actuator to the dampers. Also, changes to the positioner will make the control loop less sensitive. The draft transmitter on HTWG No. 3 did not correspond with the input definition, which was causing errors in measurement. It was also observed that HTWG No. 2 had a problem with draft control. The dampers appeared to be open too far at light off. As a matter of fact, the dampers did not open until the FD was at 40 percent of travel.

FD and O_2 Trim need some work, but nothing major. Cascade control needs to be removed from FD control. Cascade control is not necessary and can confuse people on site. O_2 Trim had its own special brand of problems. The configuration was incorrect. Researchers were surprised that this had never been caught before. The O_2 Trim loop output went to an F (x) block that converted the 0 to 100 percent to a 0.7 to 1.3 multiplier for the air flow signal, which is fine. After the calculation, however, the signal went to another section of the program that repeated the calculation. It was hard to determine how this was ever supposed to work. The calculations repeated exactly, as if two people had worked on the configuration, neither realizing where the other person's work had finished.

After removing the effect of one set of those blocks and making the effect of the trim from 0.85 to 1.15 rather than 0.7 to 1.3, O_2 Trim was able to be on automatic. This loop had to be seriously detuned to obtain satisfactory results. There appeared to be too much dead time in the O_2 feedback loop, and there also seemed to be tramp air. These deficiencies can be corrected by relocating the sensor closer to the boiler outlet and before the air heater. It is also recommended that the O_2 Trim affect the setpoint for the air, not the actual air flow signal. O_2 Trim can be accomplished by manipulating either the setpoint or the air flow signal, but by affecting only the setpoint, the air flow remains something the operators can rely on as being true and accurate. It also gives the setup people a reference point that will not change. At this time, setting the O_2 control point in the boiler is done manually, but by adding an F (x) block that is following the Btu signal, this can be accomplished automatically. There would also be the provision that, if the Btu signal were to become inaccurate, the setpoint could then be referenced from the demand signal. The F (x) block is tunable, so changes to control points can be made online without the need of major configuration changes.

The overall control of the plant is not very efficient. There should be separate plant and boiler master controllers. At this time, the boilers are controlled by their own (separate) control loops, each one trying to control the water temperature. To bias a boiler up or down, the water setpoints are adjusted for each boiler. The control hierarchy should be a single plant master controller for the water temperature that sends out a demand signal to each boiler. Each boiler in turn has its own boiler master controller, which allows the boiler to be biased based on load conditions and characteristics of the individual boilers. The recommended change is to go with a plant master/boiler master convention for most boiler plants. This eliminates any control problems caused by the boilers attempting to fight for control of the temperature loop.

Among minor problems noticed, HTWG No. 2 will not light off if the boiler master is in manual. The cause of this problem could not be determined, but it requires further investigation. During light-off, the gas controller should do the same in automatic mode as in manual mode.

Two more visits will be needed to bring the central heat plant up to required performance standards. One visit should be during shutdown to make configuration changes and various mechanical adjustments to actuators and linkages. The second trip should be made in the autumn, when the system load is enough to bring the boilers up to their full capacity. During this visit, combustion adjustments and settings will be made to FD and O_2 Trim control points. Reconfiguration and optimization cost is estimated at $26,100.

Develop New Operation Instructions

The fuel bed control should be adjusted to maintain:

- a bed depth of 8 to 9 in.
- an even distribution side-to-side and front-to-back
- an even distribution of coal to the rear wall (no sneaking air)

- an increase in ash fusion temperature specification to stop clinkering
- better coal sizing
- "just-in-time" delivery of coal to prevent breakdown in size caused by coal sitting in stockpile.

New combustion gas sensors for O_2 and CO should be installed between the HTWG outlet and MDC inlet, and new flue gas temperature indicators should be installed at the furnace outlet. Three sets of instruments would be installed on each coal-fired generator across the width of the generator, basically in line with the coal feeders. Smoke density meters should be installed before the baghouse. These instruments will give the operators an indication of the combustion process and allow adjustments to maintain even coal combustion across the flue bed and lower emissions.

The cost estimates for one coal boiler are:

CO – O_2 – Temperature (three per HTWG)

	Material	Labor	Subtotal
CO – O_2 Analyzer (one unit)	$ 12,000	$4,000	
Temperature (2,000 °F) (one unit)	3,000	2,500	
Subtotal for one unit	$15,000	$6,500	$21,500
Subtotal for three units	$45,000	$19,500	$64,500
INFI 90 Computer			
Two Cards	$ 8,000		
Service Engineer (5 days)		$4,250	
Car, Meals, and Flight		1,950	
Subtotal	$ 8,000	$6,200	$14,200
Smoke Density (one per HTWG)			
Smoke density analyzer	$ 6,000	$5,000	
Computer Card of INFI 90 will also take this input			
Service Engineer (1)		850	
Expenses		150	
	$ 6,000	$6,000	$ 12,000
Subtotal			$ 90,700
Contractor Overhead and Profit			$ 17,000
Subtotal			$107,700
Contingency			$ 10,800
Total cost for one generator			$118,500
Total cost for two generators			$237,000

O&M Considerations for Stack Testing

The U.S. Environmental Protection Agency (EPA) allows NOx emission sampling to be performed anywhere after the HTWG outlet where the test port is located at least two equivalent diameters downstream of a flow disturbance and at least one-half equivalent diameters upstream of a flow disturbance. The breeching between the MDC outlet and the air preheater inlet meets this criteria. Better NOx emission test results may be obtained by sampling at this location, where air infiltration across the air preheater would not affect the results.

The SDA inlet sampling ports may also be a good location to install a flow meter for measuring volumetric air flow because the velocity pressure is relatively constant throughout the duct. This meter would provide the operators with a cross-check of their instrumentation for heat output.

Some procedures in preparation for an EPA compliance test will depend on the plant heating load for 1 week before the test. Other procedures are not weather dependent. The following are the recommended minimum procedures:

1. Check the calibration of the coal scale and ensure that properly sized coal is evenly distributed in the coal bunker.
2. Check the calibration of water temperatures, flue gas temperatures, water flow, Btu output, O_2 monitors, and CO monitors.
3. Weather permitting, the generator should be on-line for 5 days at the testing load required. The boiler internals, refractory, casing, breeching, and pollution control equipment need 5 days to stabilize temperature and expansion of the materials to prevent small particles from flaking off and ending up as particulate in the EPA train.
4. Two days are required to get correct lime milk solids content and flow rates to the head tank and nozzles of the spray dryer.
5. Two days are needed to get the correct filter cake material on the baghouse bags and establish a good baghouse cleaning cycle.

Appendix B gives the recommended Stack Test Protocol.

The current operating permit language should be revised to allow by-pass during startup. This will prevent flue gas from going through dew point and creating acid, which eats the bag stitching.

7 Fuel Use and NOx Emission Control Alternatives

One option for alternative fuel use would be to convert a portion of natural gas usage to coal. The HTWG operational test determined that stable coal combustion is achievable down to 23 MMBtu/hr heat output. The plant typically burns natural gas at lower loads for easier operation. By switching a portion of the natural gas usage to coal, a fuel savings will be realized.

Existing Heating Plant Operation

Coal	125 days (4.11 months)	7,779.2 tons	65 % Energy
Natural Gas	118.2 days (3.89 months)	118,599.6 MCF	35% Energy
Off-line (Not Operating)	(4.00 months)		

Operating Cost:

Coal	$ 536,765
Natural Gas	$ 557,418
Total Fuel	$1,094,183
Other Operating	$1,155,721
Total Operating	$2,249,904

Revised Existing Heating Plant Operation

Coal	216 days (7.11 months)	11,114.8 tons	93% energy
Natural Gas	27 days (0.890 months)	23,960.0 MCF	7% energy
Off-line (Not Operating)	(4.00 months)		

Operating Cost:

Coal	$ 766,921
Natural Gas	$ 112,612

Total Fuel	$ 879,533
Other Operating Costs	$1,155,721
Total Operating Costs	**$2,035,254**
Construction for:	
Variable speed drives	457,800
Air heater modifications	$319,200
O_2 and CO Monitors and Temperature	$237,000
Total Construction Cost	**$1,014,000**

NOx at 0.45 lb/10^6 Btu to 0.50 lb/10^6 Btu of Heat Input with correct size coal and 200 °F higher ash fusion temperature (i.e., "*No Clinkers*").

Co-Firing: 90 Percent Coal Plus 10 Percent Natural Gas

Co-firing coal and natural gas in stoker boilers has been successfully accomplished at several facilities, including Dover Light & Power, Oberlin College, Hoover Company, and Ford Motor Company. A co-firing system will typically have one or more natural gas burners located in the sidewalls of the stoker. The most advantageous method has been to locate two burners near opposite corners to develop a circular flow pattern. This creates a better mixing zone for combustion. The amount of natural gas co-fired is adjusted to improve particulate emissions, low load performance, efficiency, and cost effectiveness.

Coal: 216 days (7.11 months)	10,003.3 tons
Natural Gas: 243 days (0.89 months @ 100% Gas)	55,496 MCF
Off-line (Not Operating) (4.00 months)	
Operating Cost: Coal	$ 690,228
Natural Gas	$ 260,831
Total Fuel	$ 951,059
Other Operating	$1,145,210
Total Operating	$2,096,269
Construction for:	
Variable Speed Generators	$ 457,800

Air Heater Modifications (two generators)	\$ 319,200
O_2 and CO Monitors and Temperature	\$ 237,000
Burners (2 units)	\$ 847,400
	\$1,901,400

Coal 90% x (0.45 lb/10^6 Btu) = 0.405

Natural Gas 10% x (0.10 lb/10^6 Btu) = 0.010

Average Emission = 0.415 lb/NOx/10^6 Btu

Co-Firing: 80 Percent Coal Plus 20 Percent Natural Gas

Coal: 216 days (7.11 months)	8,891.8 tons
Natural Gas: 243 days (0.89 months, 100% gas)	87,032 MCF
Off-line (Not Operating) (4.00 months)	
Operating Cost:	
Coal	\$ 613,534
Natural Gas	\$ 409,051
Total Fuel	\$1,022,585
Other Operating Costs	\$1,135,881
Total Operating Costs	\$2,158,466
Construction for:	
Air Heater	\$ 319,200
O_2 and CO Monitors and Temperature	\$ 237,000
Burners (2 units)	\$ 887,000
Total	\$1,443,600

Coal 80% x 0.45 lb/10^6 = 0.36

Natural Gas 20% x 0.10 lb/10^6 = 0.02

Average Emissions = 0.38 lb/NOx/10^6 Btu

Detroit Stoker Third Row of OFA

Coal: 216 days (7.11 months) 11,114.8 tons	93% Energy
Natural Gas: 27 days (0.890 months) 23,960.0 MCF	7% Energy
Off-line (Not Operating) (4.00 months)	
Operating Cost:	
Coal	$ 766,921
Natural Gas	$ 112,612
Total Fuel	$ 879,533
Other Operating Costs	$1,155,721
Total Operating Costs	$2,035,254
Construction for:	
OFA	$ 825,000
Variable Speed Drives (two generators)	$ 457,800
Air Heater Modifications	$ 319,200
O_2 and CO Monitors and Temperature	$ 237,000
Total	$1,839,000

NOx emission 0.45 lb/10^6 to 0.405 lb/10^6 Btu with correct size coal and 200 °F higher ash fusion temperature (i.e., "*No Clinkers*").

Detroit Stoker: Third Row of OFA Plus 3 Percent Methane

Add third level of OFA to existing two levels. Add low row of flue gas recirculation and injection of 3 percent methane (natural gas) to the lowest level of OFA. The upper two levels will have combustion air and will require a new OFA fan. The lower level flue gas recirculation will remove clean flue gas after the ID fan where the static pressure is 0" or near 0" to minimize the fan horsepower. Use 97 percent coal plus 3 percent natural gas when firing coal.

Coal: 216 days (7.11 months) 10,781.4 tons	90% Energy
Natural Gas: 243 days (0.89 months of 100% natural gas) 33,421 MCF	10% Energy

Operating Cost:	
Coal	$ 743,914
Natural Gas	$ 157,079
Total Fuel	$ 900,993
Other Operating Costs	$1,155,697
Total Operating Costs	$2,056,690
Construction for:	
Detroit Methane	$1,330,000
Variable Speed Drives (two generators)	$ 457,800
Air Heater Modifications	$ 319,200
O_2 and CO Monitors and Temperature	$ 237,000
Total	$2,344,000

NOx emission 0.30 lb/10^6 Btu with correct size coal and 200 °F higher ash fusion temperature (i.e., "*No Clinkers*").

Selective Non-Catalytic Reduction of Revised Existing Heating Plant Operation

A Fuel Tech NOx OUT process urea injection system should be installed to achieve a 30 percent NOx reduction. The system consists of a storage tank sized to hold approximately 2 weeks of projected urea solution supply, tank heater, control panel with circulation module and control module, electric valve actuators, inline circulation heater, piping, tubing, fittings, pressure gauges, magnetic flowmeter, temperature indicators, tank level controllers, circulation pump, metering pump, water boost pump, injector lances.

Coal: 216 days (7.105 months) 11,114.8 tons	93% Energy
Natural Gas: 27 days (0.890 months) 23,960 MCF	7% Energy
Off-line (Not Operating) (4.00 months)	
Operating Cost:	
Coal	$ 766,921
Natural Gas	$ 112,612

Total Fuel	\$ 879,533
Other Operating Costs (includes Urea and Power)	\$1,181,134
Total Operating Costs	\$2,060,691
Construction for:	
SNCR	\$2,620,000
Air heater modifications	\$ 319,200
O_2 and CO Monitors and Temperature	\$ 237,000
Total	\$3,176,200

NOx emission 0.315 lb/10^6 Btu with correct size coal and 200 °F higher ash fusion temperature (i.e., "*No Clinkers*").

100 Percent Natural Gas as Fuel

To switch to 100 percent natural gas and No. 2 fuel oil, install natural gas conversion burners in HTWG Nos. 1 and 2. The burners would fire natural gas as a primary fuel and No. 2 fuel oil as backup in the event of a natural gas supply outage. The burners would be guaranteed for NOx emissions of 0.10 lb/MMBtu.

Natural Gas: 243 days (8.00 months)	339,320.6 MCF
Operating Cost:	
Natural Gas	\$1,595,146
Other Operating Costs	\$ 704,818
Total Operating Costs	\$2,299,964
Construction Cost:	\$1,870,000

NOx emission = 0.10 lb/10^6 Btu

8 Conclusions and Recommendations

Conclusions

1. *Economical Use of Coal.* This study has found that a "no coal" approach (i.e., if Malmstrom AFB were to switch to 100 percent natural gas burners) would require a capital investment of $1,870,000 and increased operating costs of $264,000 per year. The most economical method of generating heat at MAFB is a revised operation that fires coal for a greater amount of time of the year and reduces the amount of natural gas consumption to 7 percent of total energy. About $210,000/yr could be saved by reducing natural gas consumption. This method would require (1) a non-clinkering coal, (2) air heater modifications, (3) VSDs, and (4) new combustion gas/temperature monitors.

2. *Method To Produce Artificial Load for Testing.* The EPA requires compliance testing to be conducted at 90 percent or greater of the maximum continuous rating of the generator. If the facility heat load is less than the requirement, artificial heat loads must be imposed. These artificial heat loads include:

   - *Distribution Temperature Sag* – Allowing the return water temperature to drop to 290 °F at night will increase the load approximately 14 MMBtu/hr for 6 hr.

   - *Off-Line Units as Radiators* – Circulating water through the off-line generators and turning on the ID fans increases the load approximately 8 MMBtu/hr for two generators.

3. *Better Operation to Ensure Low NOx.* Operational tests determined that NOx can be reduced to 0.40 lb/MMBtu by controlling flue gas oxygen content and maintaining even coal combustion on the grate. The oxygen content should be maintained below 4.2 percent at high generator loads and below 7.5 percent at approximately 24 MMBtu/hr. Field tests show that, without clinker formation, NOx emissions were always below 0.48 lb, and frequently below 0.45 lb/MMBtu. The ash fusion temperature of coal must be increased 200 °F and coal fines reduced by "just-in-time" delivery of coal.

4. *Maintain Furnace Draft Control at –0.05 in.* Control of furnace draft is critical to good coal combustion and minimizing emissions. As furnace draft increases, the flow of combustion air through the fuel bed will increase in thinner areas of the fuel bed causing higher formation of NOx. High furnace draft also causes air to infiltrate into the furnace due to the negative pressure, which also increases the formation of NOx.

Recommendations

1. *"NOx Compliance" Coal Specifications.* It is recommended that MAFB attempt to purchase coal that can be delivered just in time and that meets the specifications in Chapter 5.

2. *Minimize Outside Coal Storage.* Allowing the coal to weather in an outside stockpile causes degradation and increases the percentage of smaller pieces of coal in the pile. The stockpile should only be used in the event of a coal delivery stoppage. A coal splitter plate should be installed below each discharge gate where coal drops into the bunker. The splitter plate will help minimize coal segregation across the bunker, which causes segregation across the coal feeders and an uneven fuel bed.

3. *Install New Combustion Gas Sensors to "See" Fuel Bed.* It is recommended that MAFB add O_2 monitors, CO monitors, and furnace exit flue gas temperature indicators to provide operators the information required for good coal combustion and NOx control. By placing these three sets of instrumentation across the width of the generator, operators will be given early warning of conditions that contribute to uneven coal combustion and increase NOx emissions.

4. *Improve Controls/Sensors.* It is recommended that the current control system be reworked to give operators good, reliable data. The controls should be reconfigured to remove cascade loops, adjust actuator linkage, correct draft transmitters, rework O_2 trim, add a plant master controller, and rework the natural gas burner management system.

5. *Modify Ljungstrom Combustion Air Heater.* It is recommended that MAFB's Ljungstrom combustion air heater be adjusted to reduce the FD air temperature. This will reduce the effects of low ash fusion temperatures, reduce NOx by lowering ash bed temperatures, and improve SDA operation by allowing inlet temperature to be over 350 °F during the entire HTWG operating range. This adjustment may also reduce lime consumption because, under these

conditions, less lime would be wasted. Also, a higher temperature flue gas entering the SDA would allow more water to be run through the SDA, improving SO_2 removal.

6. *Install Variable Speed Drives.* It is recommended that VSDs be installed on ID and FD fans for HTWG Nos. 1 and 2. The addition of variable frequency drives for the FD and ID fans will allow better control of furnace draft and the combustion process. Fan dampers have very limited control at low generator loads. The addition of VSDs will allow better operation at lower generator loads and savings in fuel costs.

7. *Reduce Natural Gas for Spring/Autumn Seasons.* It is recommended that natural gas usage be reduced in the spring and autumn by operating the generators on coal at lower loads. Good coal combustion at lower loads can be achieved by changing the coal specifications to increase the ash fusion temperature and decrease the amount of fines in the coal by changing to "just-in-time" delivery of coal and not allowing the coal to degrade in an outside stockpile. The additional combustion monitors will also aid in operation at lower loads.

8. *Acquire and Use Portable NOx Analyzer.* It is also recommended that MAFB purchase a portable combustion analyzer that measures NOx, O_2, and CO for operator use. The analyzer would be used to spot check NOx emissions on a daily basis to ensure compliance with NOx regulations and to help operators maintain efficient combustion.

Appendix A: Field Test Data and Calculations

Malmstrom AFB Generator No. 3
March 5, 1999 Tests
Test Run No. 1

CONTROL SCREENS

		11:15	11:30	11:45	12:00	12:15	Average
Outside Air Temp	TI720	23	24	25	25	26	24.6
Supply Pressure	PI416A	278.55	280.73	282.41	283.97	286.44	282.42
Return Pressure	PI416B	241.12	242.68	244.30	246.23	248.44	244.55
System	TI413	317.37	317.88	318.20	319.13	322.57	319.03
Load Zone 1	QI417	7.60	7.81	7.78	8.27	9.50	8.19
Zone 1 Temperature	TI414	270.23	270.40	272.08	273.25	274.00	271.99
Zone 1 Flow Rate	FI417	875.50	891.87	878.91	865.75	866.90	875.79
Load Zone 2-Plant	QI418	13.79	14.07	14.15	15.08	18.04	15.03
Temp-Zone 2 Plant Return	TI415	278.02	279.35	281.36	282.20	284.88	281.16
Zone 2 and Plant Ret	FI418	1,654.80	1,655.48	1,637.10	1,652.77	1,612.97	1,642.62
HTWG System Pressure	PIC407	233.71	235.36	236.86	238.50	240.75	237.04
HTWG 3 Btu Output	QI317	63.39	62.81	62.46	63.11	68.40	64.03
HTWG 3 Inlet Temp	TI312	295.08	295.83	296.58	297.66	300.23	297.08
HTWG 3 Outlet Temp	TI311	373.42	372.58	372.25	372.91	378.63	373.96
HTWG 3 Water Flow	FI308	1,813.85	1,798.49	1,776.77	1,799.73	1,790.45	1,795.86
HTWG 3 Flue Gas Temp	TI314	374.99	377.27	374.16	377.80	381.16	377.08
SDA 3 Inlet Temp	TI730	295.67	293.88	290.67	290.53	292.02	292.55
Baghouse 3 Inlet	TI315	188.87	185.21	186.00	182.51	189.25	186.37
Baghouse 3 Outlet	TI349	179.07	179.20	178.70	180.44	179.95	179.47
Total Load	QI419	21.25	21.97	21.96	23.30	26.98	23.09
D A Tank Temp	TI207	192	192	192	192	192	192.0
Combustion Air Temp	TI725	53	53	53	54	54	53.4
SDA 3 Slurry Flow	FI734	1.43	1.33	1.36	1.59	1.32	1.41
Baghouse 3 Pressure	PDI305	2.59	2.57	2.66	2.70	2.79	2.66
Slaked Lime Storage	LIC775	5.28	5.20	5.13	5.13	5.18	5.18
HTWG 3 SO_2 Removal	AI733	1.00	1.00	1.00	1.00	1.00	1.00
HTWG 3 Stack Opacity	AI301						
Extank Level	LI409	183.42	184.70	185.74	186.94	188.31	185.82
HTWG 3 Coal Feeder	HSC312A	69.44	69.44	69.44	69.44	71.95	69.94
HTWG 3 O_2 Trim Control	AIC302	4.48	4.68	4.95	4.84	4.20	4.63

Malmstrom AFB Generator No.3 Collector Outlet/Air Heater Inlet

March 5, 1999 Run 1

Port D

		Time	Oxygen % Dry	CO ppm	NO ppm	NO_2 Ppm	NOx ppm	SO_2 Ppm	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	3% O_2 NOx lb/MMBtu	CO ppm Corrected to 3% O_2	Left Furnace Outlet Temp. °F
Right	A1	11:19	5.5%	615	256	4	260	423	420	302	0.411	714	1,455
	A2	11:21	5.2%	560	265	0	265	427	423	302	0.411	638	1,447
	A3	11:24	5.0%	443	266	4	270	435	425	304	0.413	499	1,435
	A4	11:26	5.6%	568	245	4	249	360	421	291	0.396	664	1,456
	B1	11:29	6.7%	189	259	6	265	257	441	334	0.454	238	1,448
	B2	11:31	6.3%	291	265	6	271	273	442	332	0.452	357	1,469
	B3	11:33	5.9%	170	275	6	281	330	443	335	0.456	203	1,486
	B4	11:35	5.8%	89	283	6	289	380	444	342	0.466	105	1,496
	C1	11:38	7.3%	62	265	8	273	299	453	359	0.488	82	1,498
	C2	11:40	7.3%	66	277	8	285	309	455	375	0.510	87	1,473
	C3	11:42	7.0%	64	283	8	291	296	452	374	0.509	82	1,453
	C4	11:44	6.7%	74	290	8	298	328	450	375	0.511	93	1,470
	D1	11:47	8.1%	45	278	9	286	279	456	399	0.543	63	1,435
	D2	11:49	7.5%	47	290	10	300	280	451	400	0.545	63	1,438
	D3	11:51	7.3%	51	295	10	305	273	447	401	0.546	67	1,427
Left	D4	11:53	7.2%	49	298	10	308	296	446	402	0.547	64	1,428
		AVG	6.53%	211	274	7	281	328	441.8	352	0.479	251	1,457
		AVG A	5.33%	547	258	3	261	411	422.3	300	0.408	629	1,448
		AVG B	6.18%	185	271	6	277	310	442.5	336	0.457	226	1,475
		AVG C	7.08%	67	279	8	287	308	452.5	371	0.505	86	1,474
		AVG D	7.53%	48	290	10	300	282	450.0	401	0.545	64	1,432
		AVG 2&3	6.44%	212	277	7	284	328	442.3	353	0.480	249	1,454

Spray Dry Absorber Inlet:
HTWG #3

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 1												
03/05/1999												
Static Pr=	11:15	1	7.2	271	218	286	284.5	0.3871	0.63	0.7937	56.39	45,492
-2.6		2	7.3	180	230	286	302.4	0.4114	0.97	0.9849	69.98	56,448
Duct SF=		3	7	352	234	286	301.0	0.4096	1.10	1.0488	74.52	60,112
13.444444		4	7.3	258	237	286	311.6	0.4240	0.53	0.7280	51.73	41,726
		5	7.4	291	233	292	308.6	0.4199	0.65	0.8062	57.51	46,394
		6	7	270	247	292	317.8	0.4323	0.97	0.9849	70.26	56,675
		7	6.9	241	247	292	315.5	0.4293	1.00	1.0000	71.34	57,544
		8	6.9	251	251	291	320.6	0.4362	0.41	0.6403	45.65	36,822
		9	7.5	104	243	288	324.2	0.4411	0.58	0.7616	54.18	43,708
		10	7.1	65	254	291	329.1	0.4478	0.97	0.9849	70.21	56,637
		11	7.1	71	254	291	329.1	0.4478	1.10	1.0488	74.77	60,313
		12	7.1	65	254	290	329.1	0.4478	0.52	0.7211	51.37	41,441
		13	7.5	74	213	287	284.2	0.3867	0.70	0.8367	59.49	47,985
		14	7.3	141	224	290	294.5	0.4007	0.98	0.9899	70.53	56,890
		15	7.4	144	224	290	296.7	0.4037	1.00	1.0000	71.24	57,468
	11:50	16	7.3	109	224	290	294.5	0.4007	0.52	0.7211	51.37	41,441
		Ave.	**7.21**	**180**	**237**	**289.3**	**309.0**	**0.4204**		**0.8782**	**62.53**	**50,443**

Malmstrom AFB Generator No. 3
March 5, 1999 Tests
Test Run No. 2

CONTROL SCREENS

		12:45	13:00	13:15	13:30	Average
Outside Air Temp	TI720	27	28	28	29	28.0
Supply Pressure	PI416A	291.41	295.55	298.28	301.38	296.66
Return Pressure	PI416B	253.45	256.80	259.68	262.87	258.20
System	TI413	325.16	328.10	329.70	331.12	328.52
Load Zone 1	QI417	10.80	11.91	12.55	13.09	12.09
Zone 1 Temperature	TI414	276.94	279.29	280.47	281.81	279.63
Zone 1 Flow Rate	FI417	861.71	862.87	852.39	864.60	860.39
Load Zone 2-Plant	QI418	19.76	22.54	23.20	24.37	22.47
Temp-Zone 2 Plant Return	TI415	287.80	289.22	290.82	292.32	290.04
Zone 2 and Plant Ret	FI418	1,620.59	1,670.97	1,657.51	1,618.52	1,641.90
HTWG System Pressure	PIC407	245.98	249.13	251.97	255.11	250.55
HTWG 3 Btu Output	QI317	66.80	67.65	67.39	68.07	67.48
HTWG 3 Inlet Temp	TI312	302.90	305.57	306.90	308.55	305.98
HTWG 3 Outlet Temp	TI311	381.16	384.85	386.53	387.72	385.07
HTWG 3 Water Flow	FI308	1,805.88	1,787.97	1,773.02	1,799.11	1,791.50
HTWG 3 Flue Gas Temp	TI314	382.87	378.77	378.11	379.18	379.73
SDA 3 Inlet Temp	TI730	293.10	292.20	290.53	292.17	292.00
Baghouse 3 Inlet	TI315	186.21	184.88	182.88	188.37	185.59
Baghouse 3 Outlet	TI349	179.82	178.70	179.20	179.57	179.32
Total Load	QI419	30.74	34.03	36.21	37.52	34.63
D A Tank Temp	TI207	191	191	191	191	191.0
Combustion Air Temp	TI725	57	57	58	58	57.5
SDA 3 Slurry Flow	FI734	1.45	1.39	1.39	1.34	1.39
Baghouse 3 Pressure	PDI305	2.87	2.78	2.84	2.96	2.86
Slaked Lime Storage	LIC775	5.29	5.35	5.50	5.49	5.41
HTWG 3 SO_2 Removal	AI733	1.00	1.00	1.00	1.00	1.00
HTWG 3 Stack Opacity	AI301					
Extank Level	LI409	191.58	193.47	195.19	197.00	194.31
HTWG 3 Coal Feeder	HSC312A	74.68	74.68	74.68	74.68	74.68
HTWG 3 O_2 Trim Control	AIC302	4.57	3.32	3.71	3.77	3.84

Malmstrom AFB Generator No.3 Collector Outlet/Air Heater Inlet
March 5, 1999 Run 2

Port D

	Time	Oxygen % Dry	CO ppm	NO ppm	NO_2 ppm	NOx ppm	SO_2 ppm	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	3% O_2 NOx lb/MMBtu	CO ppm Corrected to 3% O_2	Left Furnace Outlet Temp. °F
Right A1	13:09	4.1%	1,123	258	0	258	432	419	275	0.374	1,196	1,605
A2	13:11	4.2%	717	263	0	263	433	418	282	0.383	768	1,613
A3	13:13	4.0%	841	266	0	266	410	422	282	0.383	891	1,602
A4	13:15	4.1%	824	264	0	264	428	418	281	0.383	878	1,509
B1	13:01	5.3%	822	255	4	259	377	441	297	0.404	943	1,490
B2	13:03	4.8%	888	261	0	261	381	440	290	0.395	987	1,521
B3	13:05	4.5%	838	271	0	271	392	442	296	0.402	914	1,499
B4	13:07	3.8%	1,039	270	0	270	434	443	283	0.384	1,087	1,508
C1	12:53	5.7%	125	269	4	273	357	454	321	0.437	147	1,481
C2	12:55	4.8%	387	273	4	277	362	452	308	0.419	430	1,497
C3	12:57	5.0%	270	272	4	276	361	453	311	0.423	304	1,505
C4	12:59	4.1%	475	279	4	283	402	451	301	0.410	506	1,483
D1	12:45	5.8%	53	286	8	294	223	460	348	0.474	63	1,472
D2	12:47	5.4%	64	291	8	299	302	452	345	0.470	74	1,509
D3	12:49	5.2%	70	288	6	294	332	448	335	0.456	80	1,492
Left D4	12:51	4.8%	179	289	4	293	390	446	326	0.443	199	1,486
	AVG	4.73%	545	272	3	275	376	441.2	305	0.415	592	1,517
	AVG A	4.10%	876	263	0	263	426	419.3	280	0.381	933	1,582
	AVG B	4.60%	897	264	1	265	396	441.5	291	0.396	983	1,505
	AVG C	4.90%	314	273	4	277	371	452.5	310	0.422	347	1,492
	AVG D	5.30%	92	289	7	295	312	451.5	339	0.461	104	1,490
	AVG 2&3	4.74%	509	273	3	276	372	440.9	306	0.416	556	1,530

Spray Dry Absorber Inlet:
HTWG #3

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 2												
03/05/1999												
Static Pr=	12:54	1	6	404	211	290	253.3	0.3446	0.32	0.5657	40.30	32,509
-2.6	12:57	2	5.5	998	218	290	253.3	0.3446	0.34	0.5831	41.54	33,509
	13:00	3	5.6	740	219	290	256.1	0.3484	0.34	0.5831	41.54	33,509
	13:03	4	5.6	1047	222	290	259.6	0.3532	0.34	0.5831	41.54	33,509
All readings	13:05	5	5.5	818	224	290	260.2	0.3540	0.3	0.5477	39.02	31,476
at Pt. 7	13:10	6	5.5	957	229	290	266.0	0.3619	0.32	0.5657	40.30	32,509
	13:12	7	5.4	833	232	290	267.8	0.3643	0.33	0.5745	40.92	33,013
	13:14	8	5.4	1107	229	290	264.3	0.3596	0.34	0.5831	41.54	33,509
	13:16	9	5.4	930	232	290	267.8	0.3643	0.32	0.5657	40.30	32,509
	13:19	10	5.6	722	225	290	263.1	0.3579	0.34	0.5831	41.54	33,509
		11							0.35	0.5916	33.01	26,626
		12							0.34	0.5831	32.53	26,243
		13							0.29	0.5385	30.05	24,237
		14							0.34	0.5831	32.53	26,243
		15							0.34	0.5831	32.53	26,243
		16							0.32	0.5657	31.56	25,459
		Ave.	**5.55**	**856**	**224**	**290.0**	**261.1**	**0.3553**		**0.5737**	**37.55**	**30,288**

Malmstrom AFB Generator No. 3
March 5, 1999 Tests
Test Run No. 3

CONTROL SCREENS

		15:30	15:45	16:00	16:15	Average
Outside Air Temp	TI720	33	32	31	31	31.8
Supply Pressure	PI416A	308.50	309.97	311.75	313.31	310.88
Return Pressure	PI416B	268.88	270.40	271.92	274.00	271.30
System	TI413	328.76	329.44	329.70	331.04	329.74
Load Zone 1	QI417	11.98	12.36	12.24	13.10	12.42
Zone 1 Temperature	TI414	289.69	290.62	290.28	291.46	290.51
Zone 1 Flow Rate	FI417	850.05	847.70	851.81	859.97	852.38
Load Zone 2-Plant	QI418	22.36	22.85	22.81	23.63	22.91
Temp-Zone 2 Plant Return	TI415	296.83	297.76	299.51	300.35	298.61
Zone 2 and Plant Ret	FI418	1,623.36	1,621.28	1,603.91	1,634.36	1,620.73
HTWG System Pressure	PIC407	261.70	263.04	264.38	266.25	263.84
HTWG 3 Btu Output	QI317	55.35	55.08	55.24	55.18	55.21
HTWG 3 Inlet Temp	TI312	310.72	311.55	311.80	313.47	311.89
HTWG 3 Outlet Temp	TI311	375.77	375.94	376.79	377.80	376.58
HTWG 3 Water Flow	FI308	1,806.50	1,780.51	1,766.12	1,780.51	1,783.41
HTWG 3 Flue Gas Temp	TI314	365.58	364.84	364.56	366.99	365.49
SDA 3 Inlet Temp	TI730	277.77	276.73	274.83	275.27	276.15
Baghouse 3 Inlet	TI315	184.13	185.13	181.64	181.14	183.01
Baghouse 3 Outlet	TI349	179.20	178.95	178.95	179.07	179.04
Total Load	QI419	34.62	35.18	35.53	36.81	35.54
D A Tank Temp	TI207	190	189	189	189	189.3
Combustion Air Temp	TI725	62	63	64	65	63.5
SDA 3 Slurry Flow	FI734	0.85	0.89	0.85	0.93	0.88
Baghouse 3 Pressure	PDI305	2.64	2.65	2.64	2.68	2.65
Slaked Lime Storage	LIC775	6.02	6.11	6.18	6.27	6.15
HTWG 3 SO_2 Removal	AI733	1.00	1.00	1.00	1.00	1.00
HTWG 3 Stack Opacity	AI301					
Extank Level	LI409	200.26	201.04	201.81	202.84	201.49
HTWG 3 Coal Feeder	HSC312A	65.41	65.41	65.41	65.41	65.41
HTWG 3 O_2 Trim Control	AIC302	4.49	4.29	4.12	4.15	4.26

Malmstrom AFB Generator No.3 Collector Outlet/Air Heater Inlet

March 5, 1999 Run 3

Port D

		Time	Oxygen % Dry	CO ppm	NO ppm	NO_2 ppm	NOx ppm	SO_2 ppm	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	3% O_2 NOx lb/MMBtu	CO ppm Corrected to 3% O_2	Left Furnace Outlet Temp. °F
Right	A1	15:41	5.2%	62	270	4	274	422	395	312	0.425	71	1,467
	A2	15:43	5.1%	63	273	4	277	432	394	314	0.427	71	1,453
	A3	15:45	5.0%	52	275	4	279	463	393	314	0.427	59	1,471
	A4	15:47	5.2%	51	275	4	279	490	396	318	0.433	58	1,463
	B1	15:50	5.7%	49	270	4	274	432	409	322	0.439	58	1,455
	B2	15:52	5.5%	49	270	4	274	401	410	318	0.433	57	1,457
	B3	15:54	5.6%	51	272	4	276	397	409	323	0.439	60	1,463
	B4	15:56	5.4%	45	274	4	278	425	410	321	0.437	52	1,456
	C1	15:58	5.9%	45	272	4	276	391	418	329	0.448	54	1,481
	C2	16:00	6.1%	36	284	5	289	378	419	349	0.475	44	1,466
	C3	16:02	6.5%	34	283	6	289	371	417	359	0.488	42	1,438
	C4	16:04	6.0%	38	276	6	282	385	415	339	0.461	46	1,469
	D1	16:06	6.6%	34	263	6	269	372	419	336	0.458	43	1,469
	D2	16:08	6.4%	38	274	4	278	363	416	343	0.467	47	1,475
	D3	16:10	6.3%	36	280	6	286	368	413	350	0.477	44	1,468
Left	D4	16:12	6.2%	32	278	6	284	390	413	346	0.470	39	1,452
		AVG	5.79%	45	274	5	279	405	409.1	331	0.450	53	1,463
		AVG A	5.13%	57	273	4	277	452	394.5	314	0.428	65	1,464
		AVG B	5.55%	49	272	4	276	414	409.5	321	0.437	57	1,458
		AVG C	6.13%	38	279	5	284	381	417.3	344	0.468	46	1,464
		AVG D	6.38%	35	274	6	279	373	415.3	344	0.468	43	1,466
		AVG 2&3	5.81%	45	276	5	281	397	408.9	334	0.454	53	1,461

Spray Dry Absorber Inlet:
HTWG #3

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 3												
03/05/1999												
Static Pr=	15:41	1	6.4	41	240	277	296.0	0.4028	0.2	0.4472	31.58	25,477
-2.6	15:46	2	6.6	35	247	277	308.9	0.4203	0.23	0.4796	33.87	27,321
	15:49	3	6.5	30	250	276	310.5	0.4225	0.24	0.4899	34.57	27,889
	15:52	4	6.8	30	250	276	317.1	0.4314	0.24	0.4899	34.57	27,889
All readings	15:57	5	6.6	30	254	276	317.7	0.4322	0.22	0.4690	33.10	26,702
at Pt. 7	16:00	6	6.3	32	258	276	316.1	0.4300	0.22	0.4690	33.10	26,702
	16:02	7	6.7	27	263	276	331.2	0.4507	0.22	0.4690	33.10	26,702
	16:05	8	6.8	26	260	276	329.8	0.4487	0.23	0.4796	33.85	27,302
	16:07	9	6.6	29	260	276	325.2	0.4424	0.23	0.4796	33.85	27,302
	16:09	10	6.6	24	259	277	323.9	0.4407	0.25	0.5000	35.31	28,484
	16:11	11	6.3	32	260	276	318.5	0.4334	0.25	0.5000	35.29	28,464
	16:12	12	6.6	27	263	276	328.9	0.4475	0.24	0.4899	34.57	27,889
	16:15	13	6.7	24	263	277	331.2	0.4507	0.19	0.4359	30.78	24,832
		14							0.24	0.4899	27.33	22,049
		15							0.25	0.5000	27.90	22,503
		16							0.24	0.4899	27.33	22,049
		Ave.	**6.58**	**30**	**256**	**276.3**	**319.6**	**0.4349**		**0.4799**	**32.51**	**26,222**

Malmstrom AFB Generator No. 3
March 5, 1999 Tests
Test Run No. 4

CONTROL SCREENS

		16:45	17:00	17:15	Average
Outside Air Temp	TI720	31	31	31	31.0
Supply Pressure	PI416A	315.64	315.08	314.48	315.07
Return Pressure	PI416B	275.42	274.76	274.16	274.78
System	TI413	325.83	324.91	323.98	324.91
Load Zone 1	QI417	10.76	10.35	9.98	10.36
Zone 1 Temperature	TI414	293.14	292.88	292.73	292.92
Zone 1 Flow Rate	FI417	839.41	854.15	846.52	846.69
Load Zone 2-Plant	QI418	19.79	19.43	18.49	19.24
Temp-Zone 2 Plant Return	TI415	300.18	299.60	300.19	299.99
Zone 2 and Plant Ret	FI418	1,613.66	1,596.91	1,647.34	1,619.30
HTWG System Pressure	PIC407	267.83	267.23	266.70	267.25
HTWG 3 Btu Output	QI317	44.99	45.95	44.40	45.11
HTWG 3 Inlet Temp	TI312	311.46	310.55	310.23	310.75
HTWG 3 Outlet Temp	TI311	363.50	364.02	361.99	363.17
HTWG 3 Water Flow	FI308	1,804.65	1,774.89	1,800.96	1,793.50
HTWG 3 Flue Gas Temp	TI314	362.88	363.41	358.30	361.53
SDA 3 Inlet Temp	TI730	274.97	269.95	267.77	270.90
Baghouse 3 Inlet	TI315	185.63	185.75	180.64	184.01
Baghouse 3 Outlet	TI349	178.45	178.74	178.82	178.67
Total Load	QI419	30.66	29.99	28.43	29.69
D A Tank Temp	TI207	193	193	193	193.0
Combustion Air Temp	TI725	66	66	65	65.7
SDA 3 Slurry Flow	FI734	0.83	0.65	0.78	0.75
Baghouse 3 Pressure	PDI305	2.78	2.48	2.53	2.60
Slaked Lime Storage	LIC775	6.42	6.53	6.61	6.52
HTWG 3 SO_2 Removal	AI733	1.00	1.00	1.00	1.00
HTWG 3 Stack Opacity	AI301				
Extank Level	LI409	203.87	203.44	203.01	203.44
HTWG 3 Coal Feeder	HSC312A	54.47	54.47	54.47	54.47
HTWG 3 O_2 Trim Control	AIC302	7.86	6.62	6.92	7.13

Malmstrom AFB Generator No.3 Collector Outlet/Air Heater Inlet
March 5, 1999 Run 4

Port D

	Time	Oxygen % Dry	CO ppm	NO ppm	NO_2 ppm	NOx ppm	SO_2 ppm	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	3% O_2 NOx lb/MMBtu	CO ppm Corrected to 3% O_2	Left Furnace Outlet Temp. °F
Right	A2 17:05	8.3%	34	262	8	270	235	381	383	0.521	48	1,323
	A3 17:07	8.1%	37	268	8	276	273	383	385	0.524	52	1,334
	B2 16:59	8.0%	28	271	8	279	294	395	387	0.526	39	1,338
	B3 17:01	7.8%	30	267	8	274	304	395	374	0.509	41	1,341
	C2 16:54	7.8%	28	283	8	291	296	404	397	0.540	38	1,333
	C3 16:56	8.0%	28	280	10	289	292	402	400	0.545	39	1,328
	D2 16:49	8.4%	28	280	10	289	292	403	413	0.562	40	1,328
Left	D3 16:51	8.0%	28	281	10	290	300	400	402	0.547	39	1,337
	AVG	8.05%	30	274	9	282	286	395.4	393	0.534	42	1,333
	AVG A	8.20%	36	265	8	273	254	382.0	384	0.523	50	1,329
	AVG B	7.90%	29	269	8	277	299	395.0	380	0.517	40	1,340
	AVG C	7.90%	28	282	9	290	294	403.0	399	0.543	39	1,331
	AVG D	8.20%	28	281	10	290	296	401.5	408	0.555	39	1,333

Spray Dry Absorber Inlet:
HTWG #3

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 4												
03/05/1999												
Static Pr=	16:51	1	8.8	15	260	268	384.0	0.5225	0.2	0.4472	31.39	25,321
-2.6	16:53	2	8.6	15	262	268	380.7	0.5180	0.21	0.4583	32.16	25,946
	16:56	3	8.6	15	262	268	380.7	0.5180	0.23	0.4796	33.66	27,153
	16:58	4	8.6	15	262	268	380.7	0.5180	0.22	0.4690	32.92	26,557
All readings	16:59	5	8.6	15	262	268	380.7	0.5180	0.2	0.4472	31.39	25,321
at Pt. 7	17:02	6	8.5	18	259	268	373.3	0.5079	0.21	0.4583	32.16	25,946
	17:05	7	8.5	17	258	268	371.9	0.5060	0.22	0.4690	32.92	26,557
	17:07	8	8.9	18	259	267	385.7	0.5248	0.22	0.4690	32.90	26,538
	17:10	9	8.7	18	259	267	379.4	0.5162	0.24	0.4899	34.36	27,718
		10							0.22	0.4690	26.17	21,110
		11							0.22	0.4690	26.17	21,110
		12							0.23	0.4796	26.76	21,584
		13							0.17	0.4123	23.00	18,557
		14							0.2	0.4472	24.95	20,127
		15							0.22	0.4690	26.17	21,110
		16							0.21	0.4583	25.57	20,624
		Ave.	**8.64**	**16**	**260**	**267.8**	**379.7**	**0.5166**		**0.4620**	**29.54**	**23,830**

Malmstrom AFB Generator No. 3
March 5, 1999 Tests
Test Run No. 5

CONTROL SCREENS

		17:30	17:45	18:00	18:15	Average
Outside Air Temp	TI720	30	30	29	29	29.5
Supply Pressure	PI416A	311.95	311.03	309.67	309.16	310.45
Return Pressure	PI416B	272.63	271.88	270.66	269.65	271.21
System	TI413	324.32	324.82	323.32	323.48	323.99
Load Zone 1	QI417	10.24	10.33	9.85	9.88	10.08
Zone 1 Temperature	TI414	292.55	292.88	292.88	291.46	292.44
Zone 1 Flow Rate	FI417	867.48	866.90	855.90	862.87	863.29
Load Zone 2-Plant	QI418	19.22	19.29	17.94	18.20	18.66
Temp-Zone 2 Plant Return	TI415	298.43	297.01	296.84	297.76	297.51
Zone 2 and Plant Ret	FI418	1,641.20	1,631.62	1,614.36	1,620.59	1,626.94
HTWG System Pressure	PIC407	265.88	265.65	264.38	263.48	264.85
HTWG 3 Btu Output	QI317	46.53	47.99	45.04	46.07	46.41
HTWG 3 Inlet Temp	TI312	309.55	309.64	309.05	308.64	309.22
HTWG 3 Outlet Temp	TI311	364.02	364.84	361.66	362.92	363.36
HTWG 3 Water Flow	FI308	1,771.14	1,807.72	1,786.73	1,780.51	1,786.53
HTWG 3 Flue Gas Temp	TI314	358.63	361.27	361.50	360.84	360.56
SDA 3 Inlet Temp	TI730	265.25	261.44	260.30	259.20	261.55
Baghouse 3 Inlet	TI315	173.03	180.51	178.14	189.12	180.20
Baghouse 3 Outlet	TI349	180.07	178.07	177.45	177.07	178.17
Total Load	QI419	29.12	29.69	28.32	27.93	28.77
D A Tank Temp	TI207	193	193	193	193	193.0
Combustion Air Temp	TI725	66	68	70	71	68.8
SDA 3 Slurry Flow	FI734	0.75	0.53	0.59	0.27	0.54
Baghouse 3 Pressure	PDI305	2.18	2.17	2.13	2.12	2.15
Slaked Lime Storage	LIC775	6.70	6.78	6.89	6.98	6.84
HTWG 3 SO_2 Removal	AI733	1.00	1.00	1.00	1.00	1.00
HTWG 3 Stack Opacity	AI301					
Extank Level	LI409	202.41	201.89	201.29	200.78	201.59
HTWG 3 Coal Feeder	HSC312A	57.41	56.99	56.99	56.99	57.10
HTWG 3 O_2 Trim Control	AIC302	4.61	4.35	4.49	3.98	4.36

Malmstrom AFB Generator No.3 Collector Outlet/Air Heater Inlet
March 5, 1999 Run 5

	Time	Oxygen % Dry	CO ppm	NO ppm	NO_2 ppm	NOx ppm	SO_2 ppm	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	3% O_2 NOx lb/MMBtu	CO ppm Corrected to 3% O_2	Port D Left Furnace Outlet Temp. °F
Right	A1 17:36	4.5%	203	256	4	260	384	372	284	0.386	221	1,396
	A2 17:38	4.6%	163	256	4	260	401	373	285	0.388	179	1,401
	A3 17:40	4.4%	244	253	3	256	461	373	278	0.378	265	1,404
	A4 17:42	5.0%	137	253	4	256	460	375	288	0.392	154	1,399
	B1 17:45	5.5%	94	249	4	253	402	381	294	0.400	109	1,387
	B2 17:47							381				1,377
	B3 17:49	5.4%	82	246	0	246	386	380	284	0.386	95	1,391
	B4 17:51	5.4%	82	245	0	245	411	379	283	0.385	95	1,383
	C1 17:54	6.0%	48	245	4	249	358	382	299	0.407	58	1,372
	C2 17:56	5.6%	55	254	4	257	364	382	301	0.409	64	1,395
	C3 17:58	5.9%	54	254	4	258	382	380	308	0.419	64	1,368
	C4 18:00	6.0%	46	254	4	258	392	378	310	0.421	55	1,396
	D1 18:03	6.1%	59	248	4	251	378	382	303	0.413	71	1,382
	D2 18:05	6.3%	48	259	4	263	362	378	322	0.438	59	1,392
	D3 18:07	5.5%	59	254	4	258	358	376	300	0.408	69	1,388
Left	D4 18:09	5.9%	52	257	4	260	388	375	310	0.422	62	1,382
	AVG	5.47%	95	252	3	255	392	377.9	297	0.403	108	1,388
	AVG A	4.63%	187	255	4	258	427	373.3	284	0.386	205	1,400
	AVG B	5.43%	86	247	1	248	400	380.3	287	0.390	99	1,385
	AVG C	5.88%	51	252	4	256	374	380.5	304	0.414	60	1,383
	AVG D	5.95%	55	255	4	258	372	377.8	309	0.420	65	1,386
	AVG 2&3	5.39%	101	254	3	257	388	377.9	297	0.404	113	1,390

Spray Dry Absorber Inlet:
HTWG #3

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 4												
03/05/1999												
Static Pr=	16:51	1	8.8	15	260	268	384.0	0.5225	0.2	0.4472	31.39	25,321
-2.6	16:53	2	8.6	15	262	268	380.7	0.5180	0.21	0.4583	32.16	25,946
	16:56	3	8.6	15	262	268	380.7	0.5180	0.23	0.4796	33.66	27,153
	16:58	4	8.6	15	262	268	380.7	0.5180	0.22	0.4690	32.92	26,557
All readings	16:59	5	8.6	15	262	268	380.7	0.5180	0.2	0.4472	31.39	25,321
at Pt. 7	17:02	6	8.5	18	259	268	373.3	0.5079	0.21	0.4583	32.16	25,946
	17:05	7	8.5	17	258	268	371.9	0.5060	0.22	0.4690	32.92	26,557
	17:07	8	8.9	18	259	267	385.7	0.5248	0.22	0.4690	32.90	26,538
	17:10	9	8.7	18	259	267	379.4	0.5162	0.24	0.4899	34.36	27,718
		10							0.22	0.4690	26.17	21,110
		11							0.22	0.4690	26.17	21,110
		12							0.23	0.4796	26.76	21,584
		13							0.17	0.4123	23.00	18,557
		14							0.2	0.4472	24.95	20,127
		15							0.22	0.4690	26.17	21,110
		16							0.21	0.4583	25.57	20,624
		Ave.	**8.64**	**16**	**260**	**267.8**	**379.7**	**0.5166**		**0.4620**	**29.54**	**23,830**

Malmstrom AFB Generator No. 1
March 9, 1999 Tests
Test Run No. 6

CONTROL SCREENS

		9:30	9:45	10:00	10:15	Average
Outside Air Temp	TI720	43	43	44	45	43.8
Supply Pressure	PI416A	292.73	296.91	303.64	308.86	300.54
Return Pressure	PI416B	251.89	256.29	264.07	267.88	260.03
System	TI413	330.62	334.14	335.30	336.74	334.20
Load Zone 1	QI417	12.44	14.01	14.45	15.03	13.98
Zone 1 Temperature	TI414	285.42	286.27	288.10	289.87	287.42
Zone 1 Flow Rate	FI417	834.64	838.22	837.52	833.45	835.96
Load Zone 2-Plant	QI418	23.83	26.46	27.48	25.72	25.87
Temp-Zone 2 Plant Return	TI415	296.00	298.68	299.69	303.37	299.44
Zone 2 and Plant Ret	FI418	1,597.61	1,632.99	1,600.92	1,617.83	1,612.34
HTWG System Pressure	PIC407	245.30	252.27	258.85	263.48	254.98
HTWG 1 Btu Output	QI117	63.78	64.30	62.73	61.89	63.18
HTWG 1 Inlet Temp	TI112	308.96	312.89	314.30	316.22	313.09
HTWG 1 Outlet Temp	TI111	389.48	393.44	394.36	394.54	392.96
HTWG 1 Water Flow	FI108	1,660.42	1,645.15	1,655.73	1,638.19	1,649.87
HTWG 1 Flue Gas Temp	TI114	420.70	422.41	422.51	423.66	422.32
SDA 1 Inlet Temp	TI710	277.17	279.05	279.89	280.45	279.14
Baghouse 1 Inlet	TI115	209.08	205.91	207.21	206.59	207.20
Baghouse 1 Outlet	TI149	205.09	205.16	205.21	205.21	205.17
Total Load	QI419	36.28	40.56	41.85	40.65	39.84
D A Tank Temp	TI207	183	175	180	191	182.3
Combustion Air Temp	TI725	72	72	72	73	72.3
SDA 3 Slurry Flow	FI734					
Baghouse 1 Pressure	PDI105	2.22	2.31	2.39	2.46	2.35
Slaked Lime Storage	LIC775	8.44	8.41	8.35	8.32	8.38
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101					
Extank Level	LI409	181.44	186.60	190.76	193.56	188.09
HTWG 1 Coal Feeder	HSC112A	82.19	82.19	82.19	82.19	82.19
HTWG 1 O_2 Trim Control	AIC102					
Mbtu Modified	QI118	60	60	60	60	60.0

Malmstrom AFB Generator No.1 Collector Outlet/Air Heater Inlet
March 9, 1999 Run 6

		Time	Oxygen % Dry	CO ppm	NO ppm	NO_2 ppm	NOx ppm	SO_2 ppm	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	3% O_2 NOx lb/MMBtu	Left Furnace Outlet Temp. °F	Right Furnace Outlet Temp. °F
Left	A1	9:34	6.1%	391	259	4	262	461	401	317	0.431	1,605	1,384
	A2	9:36	5.2%	412	268	4	272	434	396	310	0.422	1,603	1,365
	A3	9:37	5.0%	564	273	4	277	421	393	312	0.424	1,610	1,377
	A4	9:39	4.5%	638	275	2	277	517	391	302	0.411	1,602	1,363
	B1	9:41	6.0%	209	255	10	265	459	410	318	0.433	1,594	1,369
	B2	9:43	5.3%	342	264	4	268	439	406	307	0.418	1,608	1,377
	B3	9:46	4.3%	135	274	0	274	454	404	295	0.402	1,607	1,365
	B4	9:47	4.3%	387	272	0	272	467	399	293	0.399	1,605	1,351
	C1	9:50	6.6%	121	260	4	264	419	415	330	0.449	1,612	1,370
	C2	9:52	6.0%	230	264	4	268	410	415	322	0.438	1,593	1,357
	C3	9:55	5.4%	20	265	0	265	404	424	306	0.416	1,602	1,365
	C4	9:57	5.1%	248	269	4	273	454	414	309	0.421	1,589	1,352
	D1	10:00	8.0%	67	271	6	276	377	412	382	0.520	1,581	1,354
	D2	10:02	7.9%	82	275	8	282	348	411	388	0.528	1,585	1,336
	D3	10:04	7.4%	88	275	8	282	341	410	374	0.508	1,585	1,342
Right	D4	10:06	6.9%	41	275	12	286	390	411	365	0.497	1,597	1,358
		AVG	5.88%	248	268	5	273	425	407.0	327	0.445	1,599	1,362
		AVG A	5.20%	501	269	4	272	458	395.3	310	0.422	1,605	1,372
		AVG B	4.98%	268	266	4	270	455	404.8	304	0.413	1,604	1,366
		AVG C	5.78%	155	265	3	268	422	417.0	317	0.431	1,599	1,361
		AVG D	7.55%	70	274	9	282	364	411.0	377	0.513	1,587	1,348
		AVG 2&3	5.81%	234	270	4	274	406	407.4	327	0.444	1,599	1,361

Spray Dry Absorber Inlet:
HTWG #1

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 6												
03/09/1999												
Static Pr=	9:36	1	7.5	501	238	280	317.6	0.4321	0.34	0.5831	41.31	33,323
-3.4	9:38	2	8.3	486	220	281	312.1	0.4246	0.34	0.5831	41.34	33,345
Duct SF=	9:40	3	16.3	258	144	282	555.0	0.7551	0.34	0.5831	41.37	33,368
13.444444	9:42	4	12.8	177	106	261	233.3	0.3174	0.34	0.5831	40.78	32,892
	9:45	5	11.1	238	153	278	278.7	0.3792	0.24	0.4899	34.66	27,959
	9:47	6	8.6	364	211	282	306.6	0.4171	0.25	0.5000	35.47	28,613
	9:49	7	12.5	153	159	283	337.5	0.4592	0.24	0.4899	34.78	28,053
	9:51	8	7.6	186	216	265	290.4	0.3951	0.25	0.5000	35.06	28,283
	9:54	9	16.3	69	105	280	404.7	0.5506	0.35	0.5916	41.91	33,809
	9:59	10	13.0	118	137	280	309.1	0.4206	0.34	0.5831	41.31	33,323
	10:02	11	15.0	68	111	283	334.5	0.4551	0.32	0.5657	40.16	32,393
	10:03	12	11.8	98	159	283	311.8	0.4242	0.29	0.5385	38.23	30,838
	10:06	13	11.4	112	154	281	289.3	0.3936	0.35	0.5916	41.94	33,832
	10:07	14	13.4	131	175	283	415.7	0.5656	0.34	0.5831	41.39	33,390
	10:11	15	11.5	141	153	284	290.5	0.3952	0.35	0.5916	42.03	33,901
	10:15	16	11.7	81	241	283	467.4	0.6360	0.30	0.5477	38.88	31,365
		Ave.	**11.80**	**199**	**168**	**279.3**	**340.9**	**0.4638**		**0.5566**	**39.41**	**31,793**

Malmstrom AFB Generator No. 1
March 9, 1999 Tests
Test Run No. 7

CONTROL SCREENS

		11:00	11:15	11:30	11:45	Average
Outside Air Temp	TI720	45	46	46	46	45.8
Supply Pressure	PI416A	323.13	337.60	341.98	347.82	337.63
Return Pressure	PI416B	281.84	295.96	300.66	306.48	296.24
System	TI413	336.23	340.84	343.85	344.62	341.39
Load Zone 1	QI417	14.68	16.10	17.09	17.55	16.36
Zone 1 Temperature	TI414	293.80	296.07	297.33	300.45	296.91
Zone 1 Flow Rate	FI417	819.56	818.24	820.78	822.60	820.30
Load Zone 2-Plant	QI418	23.27	25.75	24.55	23.87	24.36
Temp-Zone 2 Plant Return	TI415	305.71	307.55	310.73	313.07	309.27
Zone 2 and Plant Ret	FI418	1,606.71	1,579.98	1,586.35	1,577.86	1,587.73
HTWG System Pressure	PIC407	274.26	289.38	294.84	300.74	289.81
HTWG 1 Btu Output	QI117	57.45	63.29	62.07	57.29	60.03
HTWG 1 Inlet Temp	TI112	316.64	320.23	323.51	325.18	321.39
HTWG 1 Outlet Temp	TI111	389.98	400.06	401.26	399.73	397.76
HTWG 1 Water Flow	FI108	1,634.31	1,654.39	1,640.42	1,619.08	1,637.05
HTWG 1 Flue Gas Temp	TI114	418.05	424.91	430.23	432.48	426.42
SDA 1 Inlet Temp	TI710	277.11	278.10	279.82	320.74	288.94
Baghouse 1 Inlet	TI115	208.33	205.71	206.46	201.10	205.40
Baghouse 1 Outlet	TI149	205.21	205.34	204.97	206.09	205.40
Total Load	QI419	37.81	42.03	42.16	41.38	40.85
D A Tank Temp	TI207	191	193	195	196	193.8
Combustion Air Temp	TI725	72	72	72	73	72.3
SDA 3 Slurry Flow	FI734					
Baghouse 1 Pressure	PDI105	2.49	2.53	2.79	2.95	2.69
Slaked Lime Storage	LIC775	8.17	8.13	8.07	8.00	8.09
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101					
Extank Level	LI409	199.49	207.05	209.80	212.47	207.20
HTWG 1 Coal Feeder	HSC112A	79.88	84.07	82.81	80.08	81.71
HTWG 1 O_2 Trim Control	AIC102					
Mbtu Modified	QI118	59	60	64	57	60.0

Malmstrom AFB Generator No.1 Collector Outlet/Air Heater Inlet March 9, 1999 Run 7

		Time	Oxygen % Dry	CO ppm	NO ppm	NO_2 ppm	NOx ppm	SO_2 ppm	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	3% O_2 NOx lb/MMBtu	Left Furnace Outlet Temp. °F	Right Furnace Outlet Temp. °F
Left	A1	11:07	6.0%	131	270	6	276	382	399	331	0.451	1,594	1,367
	A2	11:09	5.1%	360	275	6	280	416	396	317	0.431	1,596	1,357
	A3	11:11	4.8%	398	279	4	282	538	394	313	0.426	1,591	1,370
	A4	11:13	4.8%	293	283	7	289	657	393	321	0.437	1,607	1,387
	B1	11:16	5.8%	178	270	6	275	458	408	326	0.443	1,576	1,337
	B2	11:18	6.2%	111	277	6	283	437	405	344	0.469	1,558	1,340
	B3	11:20	5.6%	139	283	6	288	419	401	337	0.458	1,563	1,347
	B4	11:21	5.0%	158	289	6	295	493	399	332	0.452	1,570	1,352
	C1	11:24	6.8%	75	269	6	275	433	417	349	0.475	1,549	1,320
	C2	11:25	7.3%	67	270	8	277	412	418	364	0.496	1,565	1,317
	C3	11:27	7.0%	75	272	8	279	397	420	359	0.488	1,563	1,331
	C4	11:29	6.1%	79	277	10	286	389	417	346	0.470	1,548	1,311
	D1	11:33							418			1,553	1,324
	D2												
	D3												
Right	D4												
		AVG	5.88%	172	276	7	282	453	406.5	337	0.458	1,572	1,343
		AVG A	5.18%	296	277	6	282	498	395.5	321	0.436	1,597	1,370
		AVG B	5.65%	147	280	6	285	452	403.3	335	0.455	1,567	1,344
		AVG C	6.80%	74	272	8	279	408	418.0	354	0.482	1,556	1,320
		AVG D							418.0			1,553	1,324
		AVG 2&3	6.00%	192	276	6	282	437	406	339	0.461	1,573	1,344

Spray Dry Absorber Inlet:
HTWG #1

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 7												
03/09/1999												
Static Pr=	11:10	1	9.4	194	186	273	289.0	0.3932	0.20	0.4472	31.51	25,422
-3	11:12	2	10.5	218	175	279	300.5	0.4088	0.22	0.4690	33.19	26,772
	11:14	3	9.6	221	181	280	286.2	0.3893	0.23	0.4796	33.96	27,392
	11:16	4	7.2	277	217	280	283.2	0.3854	0.25	0.5000	35.40	28,558
	11:18	5	9.3	216	221	279	340.4	0.4631	0.21	0.4583	32.42	26,156
	11:19	6	9.9	92	193	281	313.4	0.4264	0.22	0.4690	33.23	26,808
	11:20	7	9.0	88	211	279	316.9	0.4311	0.23	0.4796	33.93	27,373
	11:22	8	10.5	98	214	276	367.4	0.4999	0.22	0.4690	33.12	26,717
	11:24	9	11.8	66	164	282	321.6	0.4375	0.30	0.5477	38.83	31,326
	11:25	10	10.5	55	.182	282	312.5	0.4252	0.31	0.5568	39.48	31,844
	11:27	11	10.7	38	193	282	337.8	0.4597	0.28	0.5292	37.52	30,264
	11:29	12	10.8	38	193	281	341.2	0.4642	0.25	0.5000	35.43	28,577
	11:31	13	9.2	61	210	284	320.7	0.4363	0.30	0.5477	38.89	31,368
	11:33	14	11.0	46	193	285	348.0	0.4735	0.31	0.5568	39.56	31,908
No 16th pt	11:35	15	10.2	55	189	285	315.5	0.4292	0.30	0.5477	38.91	31,389
Probe was									0.27	0.5196	29.01	23,399
plugging		**Ave.**	**9.97**	**118**	**195**	**280.5**	**319.6**	**0.4349**		**0.5048**	**35.27**	**28,454**

Malmstrom AFB Generator No. 1
March 10, 1999 Tests
Test Run No. 8

CONTROL SCREENS

		15:45	16:00	16:15	16:30	Average
Outside Air Temp	TI720	48	48	48	48	48.0
Supply Pressure	PI416A	279.27	280.32	282.09	283.26	281.24
Return Pressure	PI416B	237.42	238.88	240.70	241.82	239.71
System	TI413	310.38	311.93	312.70	310.95	311.49
Load Zone 1	QI417	4.38	4.99	5.27	4.96	4.90
Zone 1 Temperature	TI414	278.88	279.53	279.13	280.47	279.50
Zone 1 Flow Rate	FI417	834.05	844.16	837.03	834.05	837.32
Load Zone 2-Plant	QI418	7.75	9.19	9.82	9.15	8.98
Temp-Zone 2 Plant Return	TI415	287.64	288.20	289.48	290.90	289.06
Zone 2 and Plant Ret	FI418	1,631.62	1,618.52	1,589.88	1,623.36	1,615.85
HTWG System Pressure	PIC407	234.31	235.81	237.61	238.80	236.63
HTWG 1 Btu Output	QI117	41.08	42.45	43.09	35.62	40.56
HTWG 1 Inlet Temp	TI112	295.62	296.94	297.04	297.62	296.81
HTWG 1 Outlet Temp	TI111	351.82	353.48	354.85	345.51	351.42
HTWG 1 Water Flow	FI108	1,655.26	1,634.11	1,657.74	1,628.66	1,643.94
HTWG 1 Flue Gas Temp	TI114	368.60	372.97	368.74	368.09	369.60
SDA 1 Inlet Temp	TI710	247.88	247.83	248.02	247.83	247.89
Baghouse 1 Inlet	TI115	193.99	198.23	197.73	195.48	196.36
Baghouse 1 Outlet	TI149	199.35	198.18	197.85	197.11	198.12
Total Load	QI419	12.11	14.25	15.12	14.04	13.88
D A Tank Temp	TI207	190	190	190	190	190.0
Combustion Air Temp	TI725	73	73	72	73	72.8
SDA 3 Slurry Flow	FI734					
Baghouse 1 Pressure	PDI105	1.30	1.31	1.34	1.33	1.32
Slaked Lime Storage	LIC775	9.24	9.35	9.48	9.56	9.41
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101					
Extank Level	LI409	178.69	179.72	180.92	181.95	180.32
HTWG 1 Coal Feeder	HSC112A	71.74	71.74	71.74	60.18	68.85
HTWG 1 O_2 Trim Control	AIC102					
Mbtu Modified	QI118	45	45	45	45	45.0

Generator No.1 Collector Outlet/Air Heater Inlet
March 10, 1999 Run 8

CO, NO, NO_2, NOx, & SO_2 corrected to 3% O_2

		Time	Oxygen % Dry	3% O_2 CO ppm	3% O_2 NO ppm	3% O_2 NO_2 ppm	3% O_2 NOx ppm	3% O_2 SO_2 ppm	Flue Gas Temp. °F	3% O_2 NOx lb/MMBtu	Port D Left Furnace Outlet Temp. °F	Port A Right Furnace Outlet Temp. °F	Plant Rosemont Oxygen % Wet
Right	A1	15:48	7.6%	76	345	1	346	546	365	0.471	1,318	1,259	6.90%
	A2	15:50	7.5%	78	340	1	341	554	366	0.464	1,344	1,280	6.80%
	A3	15:52	8.0%	88	354	1	355	631	360	0.483	1,355	1,251	6.80%
	A4	15:54	7.4%	91	342	1	344	611	358	0.468	1,367	1,257	6.90%
	B1	15:57	8.2%	47	365	1	367	587	363	0.499	1,323	1,239	7.00%
	B2	15:59	8.3%	43	368	1	369	592	362	0.502	1,322	1,239	6.80%
	B3	16:02	8.1%	41	373	1	375	620	360	0.510	1,343	1,271	6.60%
	B4	16:04	8.0%	33	369	1	371	606	341	0.505	1,342	1,261	6.80%
	C1	16:06	8.6%	36	387	1	389	616	359	0.529	1,338	1,279	6.60%
	C2	16:08	8.2%	29	383	1	385	585	359	0.524	1,362	1,274	6.70%
	C3	16:10	7.4%	29	373	1	374	549	354	0.509	1,354	1,252	6.80%
	C4	16:12	7.8%	28	379	1	380	587	353	0.517	1,363	1,250	6.60%
	D1	16:15	8.2%	32	379	1	381	568	356	0.518	1,344	1,273	6.90%
	D2	16:17	7.7%	37	369	1	370	571	355	0.503	1,358	1,229	6.90%
	D3	16:19	7.6%	52	370	1	372	566	350	0.506	1,365	1,256	6.50%
Left	D4	16:21	7.1%	42	379	1	380	568	351	0.517	1,323	1,234	6.80%
	AVG		7.86%	49	367	1	369	585	357.0	0.502	1,345	1,257	6.78%
	AVG A		7.63%	83	345	1	347	586	362.3	0.471	1,346	1,262	6.85%
	AVG B		8.15%	41	369	1	371	601	356.5	0.504	1,333	1,253	6.80%
	AVG C		8.00%	31	381	1	382	584	356.3	0.520	1,354	1,264	6.68%
	AVG D		7.65%	41	374	1	376	568	353.0	0.511	1,348	1,248	6.78%
	AVG 2&3		7.85%	50	366	1	368	584	358	0.500	1,350	1,257	6.74%

Spray Dry Absorber
Inlet

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	Oxygen % wet	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 8													
03/10/1999													
Static Pr=	15:56	1	10.6	41	188	245	325.9	0.4434	0.14	9.9	0.3742	24.17	19,500
-2.6	15:58	2	9.3	41	196	251	301.9	0.4107	0.15	8.7	0.3873	25.13	20,270
Duct SF=	16:00	3	9.1	38	205	250	310.4	0.4224	0.15	8.5	0.3873	25.11	20,255
13.444444	16:01	4	9.2	35	206	250	314.6	0.4280	0.16	8.6	0.4000	25.93	20,920
	16:03	5	10.2	41	187	246	312.1	0.4247	0.15	9.6	0.3873	25.04	20,198
Baro. Pr=	16:04	6	8.8	44	209	252	308.7	0.4200	0.15	8.2	0.3873	25.15	20,284
29.92	16:06	7	8.9	41	216	252	321.7	0.4376	0.15	8.3	0.3873	25.15	20,284
	16:07	8	9.1	44	219	251	331.6	0.4512	0.15	8.5	0.3873	25.13	20,270
	16:09	9	9.5	38	208	247	326.0	0.4435	0.20	8.9	0.4472	28.93	23,339
	16:10	10	9.0	44	223	251	334.9	0.4556	0.21	8.4	0.4583	29.73	23,983
	16:12	11	8.9	47	227	248	338.1	0.4599	0.19	8.3	0.4359	28.22	22,765
	16:13	12	8.9	49	229	251	341.0	0.4640	0.16	8.3	0.4000	25.95	20,934
	16:16	13	9.0	52	220	250	330.4	0.4495	0.19	8.4	0.4359	28.26	22,797
	17:17	14	8.9	58	233	252	347.0	0.4721	0.18	8.3	0.4243	27.55	22,220
	16:18	15	8.9	55	233	257	347.0	0.4721	0.19	8.3	0.4359	28.40	22,909
	16:19	16	9.0	55	234	254	351.4	0.4781	0.18	8.4	0.4243	27.58	22,251
		Ave.	**9.21**	**45**	**215**	**250.4**	**327.7**	**0.4458**		**8.6**	**0.4100**	**26.59**	**21,449**

Malmstrom AFB Generator No. 1
March 10, 1999 Tests
Test Run No. 9

CONTROL SCREENS

		16:45	17:00	17:15	Average
Outside Air Temp	TI720	47	47	47	47.0
Supply Pressure	PI416A	281.90	281.19	280.43	281.17
Return Pressure	PI416B	240.50	239.54	238.43	239.49
System	TI413	303.12	302.11	302.20	302.48
Load Zone 1	QI417	1.46	1.07	1.09	1.21
Zone 1 Temperature	TI414	281.81	281.30	281.65	281.59
Zone 1 Flow Rate	FI417	847.70	847.70	855.90	850.43
Load Zone 2-Plant	QI418	2.49	1.80	1.64	1.98
Temp-Zone 2 Plant Return	TI415	287.05	287.22	287.72	287.33
Zone 2 and Plant Ret	FI418	1,614.36	1,616.44	1,611.58	1,614.13
HTWG System Pressure	PIC407	237.61	236.77	235.81	236.73
HTWG 1 Btu Output	QI117	25.73	24.91	24.51	25.05
HTWG 1 Inlet Temp	TI112	292.28	291.78	291.70	291.92
HTWG 1 Outlet Temp	TI111	332.65	330.97	331.39	331.67
HTWG 1 Water Flow	FI108	1,655.06	1,614.96	1,655.73	1,641.92
HTWG 1 Flue Gas Temp	TI114	354.99	344.18	344.70	347.96
SDA 1 Inlet Temp	TI710	244.25	239.92	237.29	240.49
Baghouse 1 Inlet	TI115	196.73	198.73	197.93	197.80
Baghouse 1 Outlet	TI149	197.48	197.98	197.31	197.59
Total Load	QI419	4.01	2.91	2.70	3.21
D A Tank Temp	TI207	190	190	190	190.0
Combustion Air Temp	TI725	74	75	76	75.0
SDA 3 Slurry Flow	FI734				
Baghouse 1 Pressure	PDI105	1.12	1.06	1.04	1.07
Slaked Lime Storage	LIC775	9.69	9.79	9.92	9.80
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101				
Extank Level	LI409	181.31	180.67	180.06	180.68
HTWG 1 Coal Feeder	HSC112A	59.55	59.55	59.55	59.55
HTWG 1 O_2 Trim Control	AIC102				
Mbtu Modified	QI118	32	32	32	32.0

Generator No.1 Collector Outlet/Air Heater Inlet
March 10, 1999 Run 9

CO, NO, NO_2, NOx, & SO_2 corrected to 3% O_2

		Time	Oxygen % Dry	3% O_2 CO ppm	3% O_2 NO ppm	3% O_2 NO_2 ppm	3% O_2 NOx ppm	3% O_2 SO_2 ppm	Flue Gas Temp. °F	3% O_2 NOx lb/MMBtu	Port D Left Furnace Outlet Temp. °F	Port A Right Furnace Outlet Temp. °F	Plant Rosemont Oxygen % Wet
Right	A1	17:17	9.7%	93	388	1	390	597	340	0.531	1,168	1,133	8.30%
	A2	17:19	9.2%	152	360	1	361	564	339	0.491	1,151	1,122	8.30%
	A3	17:20	9.4%	172	358	1	360	588	340	0.490	1,158	1,119	8.60%
	A4	17:21	9.4%	161	367	1	369	589	340	0.502	1,157	1,131	8.50%
	B1	17:11	10.0%	109	394	1	396	616	341	0.539	1,171	1,127	8.40%
	B2	17:12	9.7%	105	385	1	387	595	342	0.527	1,171	1,126	8.40%
	B3	17:14	9.7%	105	390	1	391	584	341	0.532	1,173	1,145	8.20%
	B4	17:15	9.9%	95	400	1	402	604	341	0.547	1,173	1,139	8.20%
	C1	17:02	9.9%	82	405	1	407	595	339	0.554	1,169	1,123	8.30%
	C2	17:04	9.6%	75	402	1	404	581	337	0.550	1,176	1,119	8.40%
	C3	17:06	9.9%	74	415	1	416	617	336	0.566	1,176	1,138	8.20%
	C4	17:08	9.8%	65	413	1	414	596	334	0.563	1,160	1,117	8.50%
	D1	16:50	9.4%	76	406	1	408	555	339	0.555	1,176	1,128	8.20%
	D2	16:53	9.2%	65	410	1	411	578	336	0.559	1,171	1,134	8.20%
	D3	16:55	8.8%	72	396	1	398	581	335	0.541	1,167	1,118	8.50%
Left	D4	16:59	9.9%	61	432	1	434	596	332	0.590	1,160	1,119	
	AVG		9.59%	98	395	1	397	590	338.3	0.540	1,167	1,127	8.35%
	AVG A		9.43%	145	368	1	370	585	339.8	0.503	1,159	1,126	8.43%
	AVG B		9.83%	104	392	1	394	600	341.3	0.536	1,172	1,134	8.30%
	AVG C		9.80%	74	409	1	410	597	336.5	0.558	1,170	1,124	8.35%
	AVG D		9.33%	69	411	1	413	578	335.5	0.562	1,169	1,125	8.30%
	AVG 2&3		9.44%	103	390	1	391	586	338	0.532	1,168	1,128	8.35%

Spray Dry Absorber
Inlet

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	Oxygen % wet	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 9													
03/10/1999	16:49	1	10.3	61	234	243	394.2	0.5364	0.08	9.7	0.2828	18.24	14,710
Static Pr=	16:50	2	10.6	72	233	242	403.9	0.5496	0.08	9.9	0.2828	18.22	14,700
-2.1	16:52	3	10.7	63	232	243	406.1	0.5525	0.08	10	0.2828	18.24	14,710
Duct SF=	16:53	4	10.5	61	234	243	401.8	0.5466	0.09	9.8	0.3000	19.34	15,603
13.444444	16:56	5	11.0	64	201	243	362.4	0.4931	0.08	10.3	0.2828	18.24	14,710
	16:57	6	10.7	64	233	243	407.9	0.5549	0.08	10	0.2828	18.24	14,710
	16:59	7	10.8	69	236	247	417.2	0.5676	0.08	10.1	0.2828	18.29	14,752
	17:00	8	10.9	66	232	243	414.2	0.5635	0.08	10.3	0.2828	18.24	14,710
	17:02	9	10.9	65	217	239	387.4	0.5271	0.10	10.3	0.3162	20.33	16,400
	17:03	10	10.7	69	234	243	409.6	0.5573	0.11	10	0.3317	21.38	17,249
	17:04	11	10.6	72	235	243	407.4	0.5543	0.10	9.9	0.3162	20.39	16,447
	17:06	12	10.6	66	237	240	410.9	0.5590	0.09	9.9	0.3000	19.30	15,569
	17:08	13	10.6	66	224	238	388.3	0.5283	0.11	9.9	0.3317	21.31	17,188
	17:10	14	10.7	66	238	240	416.6	0.5668	0.10	10	0.3162	20.34	16,411
	17:11	15	10.7	69	238	244	416.6	0.5668	0.11	10	0.3317	21.40	17,262
	17:12	16	10.5	75	238	245	408.7	0.5560	0.10	9.8	0.3162	20.42	16,470
		Ave.	**10.68**	**67**	**231**	**242.4**	**403.3**	**0.5487**		**10.0**	**0.3025**	**19.49**	**15,725**

Malmstrom AFB Generator No. 1
March 10, 1999 Tests
Test Run No. 10

CONTROL SCREENS

		17:30	17:45	18:00	18:15	Average
Outside Air Temp	TI720	47	46	45	44	45.5
Supply Pressure	PI416A	277.95	277.74	277.03	276.23	277.24
Return Pressure	PI416B	237.36	237.01	236.56	235.95	236.72
System	TI413	303.77	305.87	305.37	305.45	305.12
Load Zone 1	QI417	1.63	2.58	2.41	2.41	2.26
Zone 1 Temperature	TI414	280.72	279.29	280.80	279.71	280.13
Zone 1 Flow Rate	FI417	877.20	847.11	853.56	858.81	859.17
Load Zone 2-Plant	QI418	2.83	4.47	4.24	4.27	3.95
Temp-Zone 2 Plant Return	TI415	287.22	287.98	287.64	287.72	287.64
Zone 2 and Plant Ret	FI418	1,623.36	1,626.11	1,644.61	1,602.52	1,624.15
HTWG System Pressure	PIC407	234.61	234.31	233.86	233.27	234.01
HTWG 1 Btu Output	QI117	28.50	31.52	30.57	30.83	30.36
HTWG 1 Inlet Temp	TI112	292.11	293.20	293.03	293.29	292.91
HTWG 1 Outlet Temp	TI111	336.19	339.63	338.87	338.96	338.41
HTWG 1 Water Flow	FI108	1,643.60	1,642.25	1,636.15	1,657.74	1,644.94
HTWG 1 Flue Gas Temp	TI114	359.35	358.86	351.10	352.28	355.40
SDA 1 Inlet Temp	TI710	237.63	239.23	239.39	238.90	238.79
Baghouse 1 Inlet	TI115	196.11	195.11	196.73	193.36	195.33
Baghouse 1 Outlet	TI149	196.23	196.48	196.98	196.73	196.61
Total Load	QI419	4.53	7.06	6.66	6.69	6.24
D A Tank Temp	TI207	190	189	189	189	189.3
Combustion Air Temp	TI725	77	78	78	78	77.8
SDA 3 Slurry Flow	FI734					
Baghouse 1 Pressure	PDI105	1.21	1.21	1.08	1.11	1.15
Slaked Lime Storage	LIC775	10.10	10.11	10.19	10.19	10.15
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101					
Extank Level	LI409	179.12	178.77	178.52	178.17	178.65
HTWG 1 Coal Feeder	HSC112A	65.01	65.64	65.64	65.64	65.48
HTWG 1 O_2 Trim Control	AIC102					
Mbtu Modified	QI118	42	42	35	34	38.3

Generator No.1 Collector Outlet/Air Heater Inlet
March 10, 1999 Run 10

CO, NO, NO_2, NOx, & SO_2 corrected to 3% O_2

		Time	Oxygen % Dry	3% O_2 CO ppm	3% O_2 NO ppm	3% O_2 NO_2 ppm	3% O_2 NOx ppm	3% O_2 SO_2 ppm	Flue Gas Temp. °F	3% O_2 NOx lb/MMBtu	Port D Left Furnace Outlet Temp. °F	Port A Right Furnace Outlet Temp. °F	Plant Rosemont Oxygen % Wet
Right	A1	17:40	8.6%	105	367	1	368	580	349	0.501	1,231	1,185	7.80%
	A2	17:41	8.9%	107	377	1	379	653	350	0.516	1,226	1,197	8.10%
	A3	17:43	9.2%	88	382	1	384	652	350	0.522	1,194	1,167	8.10%
	A4	17:45	9.0%	88	393	1	394	634	349	0.536	1,222	1,182	8.20%
	B1	17:47	9.7%	57	414	1	415	621	350	0.565	1,210	1,171	8.00%
	B2	17:49	9.4%	51	409	1	411	605	350	0.559	1,228	1,185	8.00%
	B3	17:51	9.3%	41	410	1	412	589	349	0.561	1,201	1,163	8.10%
	B4	17:53	8.6%	88	341	1	342	586	344	0.465	1,226	1,197	7.00%
	C1	17:55	8.4%	80	334	1	335	584	342	0.456	1,232	1,212	7.00%
	C2	17:57	8.0%	91	325	1	326	599	340	0.444	1,229	1,207	6.70%
	C3	17:58	7.9%	72	331	0	331	603	337	0.450	1,229	1,222	6.60%
	C4	18:00	8.0%	66	332	0	332	603	337	0.452	1,227	1,219	6.60%
	D1	18:02	7.8%	61	328	0	328	575	335	0.446	1,242	1,210	6.80%
	D2	18:04	8.3%	69	344	0	344	602	333	0.468	1,236	1,223	6.80%
	D3	18:06	7.6%	72	334	0	334	568	332	0.454	1,237	1,216	6.50%
Left	D4	18:08	7.8%	69	338	0	338	600	332	0.460	1,242	1,212	6.70%
		AVG	8.53%	75	360	1	361	603	342.4	0.491	1,226	1,198	7.31%
		AVG A	8.93%	97	380	1	381	630	349.5	0.519	1,218	1,183	8.05%
		AVG B	9.25%	59	394	1	395	600	348.3	0.537	1,216	1,179	7.78%
		AVG C	8.08%	77	331	1	331	597	339.0	0.450	1,229	1,215	6.73%
		AVG D	7.88%	68	336	0	336	586	333.0	0.457	1,239	1,215	6.70%
		AVG 2&3	8.58%	74	364	1	365	609	343	0.497	1,223	1,198	7.36%

Spray Dry Absorber
Inlet

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Vel. Press. inches H_2O	Oxygen % wet	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 10													
03/10/1999	17:41	1	10.4	46	214	245	364.0	0.4952	0.07	9.8	0.2646	17.09	13,785
Static Pr=	17:43	2	10.3	46	233	248	392.6	0.5341	0.07	9.7	0.2646	17.12	13,814
-2.4	17:44	3	10.4	43	240	242	408.2	0.5553	0.08	9.8	0.2828	18.23	14,705
Duct SF=	17:45	4	10.4	43	243	247	413.3	0.5623	0.09	9.8	0.3000	19.40	15,653
13.444444	17:48	5	10.6	40	240	247	416.1	0.5661	0.08	9.9	0.2828	18.29	14,758
	17:50	6	10.4	43	247	244	420.1	0.5715	0.08	9.8	0.2828	18.26	14,726
	17:51	7	10.3	43	247	242	416.1	0.5662	0.08	9.7	0.2828	18.23	14,705
	17:53	8	10.3	40	247	246	416.1	0.5662	0.08	9.7	0.2828	18.28	14,747
	17:55	9	9.7	66	214	246	341.3	0.4644	0.11	9	0.3317	21.44	17,292
	17:57	10	9.2	72	228	252	348.2	0.4737	0.12	8.6	0.3464	22.49	18,138
	17:58	11	8.9	75	225	247	335.1	0.4559	0.11	8.3	0.3317	21.45	17,305
	18:00	12	8 8	80	225	249	332.3	0.4521	0.10	8.2	0.3162	20.48	16,523
	18:01	13	10.3	60	204	242	343.7	0.4676	0.11	9.7	0.3317	21.38	17,243
	18:02	14	9.0	77	219	249	328.9	0.4474	0.11	8.4	0.3317	21.48	17,329
	18:03	15	9.1	75	224	250	339.2	0.4615	0.11	8.5	0.3317	21.50	17,341
	18:05	16	9.1	80	224	250	339.2	0.4615	0.10	8.5	0.3162	20.50	16,534
		Ave.	**9.83**	**58**	**230**	**246.6**	**372.1**	**0.5063**		**9.2**	**0.3050**	**19.73**	**15,912**

Malmstrom AFB Generator No. 1
March 11, 1999 Tests
Test Run No. 11

CONTROL SCREENS

		9:45	10:00	10:15	10:30	Average
Outside Air Temp	TI720	34	35	36	36	35.3
Supply Pressure	PI416A	313.92	319.64	326.27	332.33	323.04
Return Pressure	PI416B	273.59	279.66	285.99	291.29	282.63
System	TI413	327.85	330.95	332.63	330.95	330.60
Load Zone 1	QI417	11.47	12.83	13.45	12.37	12.53
Zone 1 Temperature	TI414	275.27	277.03	278.95	282.30	278.39
Zone 1 Flow Rate	FI417	835.24	856.48	845.93	836.44	843.52
Load Zone 2-Plant	QI418	22.02	23.83	25.66	23.68	23.80
Temp-Zone 2 Plant Return	TI415	288.89	291.73	295.16	296.67	293.11
Zone 2 and Plant Ret	FI418	1,632.99	1,592.70	1,597.61	1,586.35	1,602.41
HTWG System Pressure	PIC407	267.08	273.21	279.50	284.59	276.10
HTWG 1 Btu Output	QI117	70.50	71.00	68.04	53.36	65.73
HTWG 1 Inlet Temp	TI112	304.13	306.96	309.71	309.63	307.61
HTWG 1 Outlet Temp	TI111	393.18	395.24	395.93	377.71	390.52
HTWG 1 Water Flow	FI108	1,643.13	1,643.60	1,618.40	1,631.39	1,634.13
HTWG 1 Flue Gas Temp	TI114	419.34	430.08	427.56	427.23	426.05
SDA 1 Inlet Temp	TI710	278.78	282.80	282.86	283.57	282.00
Baghouse 1 Inlet	TI115	199.35	198.85	198.35	196.73	198.32
Baghouse 1 Outlet	TI149	196.11	195.86	196.48	195.98	196.11
Total Load	QI419	33.47	36.44	38.48	35.37	35.94
D A Tank Temp	TI207	193	194	194	194	193.8
Combustion Air Temp	TI725	66	66	66	66	66.0
SDA 3 Slurry Flow	FI734					
Baghouse 1 Pressure	PDI105	3.41	1.41	1.73	2.00	2.14
Slaked Lime Storage	LIC775	8.91	8.83	8.77	8.73	8.81
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101					
Extank Level	LI409	197.25	200.78	204.22	207.05	202.33
HTWG 1 Coal Feeder	HSC112A	89.50	88.87	88.87	47.50	78.69
HTWG 1 O_2 Trim Control	AIC102					
Mbtu Modified	QI118	69	70	68	68	68.75

Generator No.1 Collector Outlet/Air Heater Inlet

March 11, 1999 Run 11

CO, NO, NO_2, NOx, & SO_2 corrected to 3% O_2

		Time	Oxygen % Dry	3% O_2 CO ppm	3% O_2 NO ppm	3% O_2 NO_2 ppm	3% O_2 NOx ppm	3% O_2 SO_2 ppm	Flue Gas Temp. °F	3% O_2 NOx lb/MMBtu	Port D Left Furnace Outlet Temp. °F	Port A Right Furnace Outlet Temp. °F	Plant Rosemont Oxygen % Wet
Right	A1	10:09	4.4%	1,843	326	1	327	479	421	0.445	1,594	1,407	4.0%
	A2	10:11	7.0%	675	353	1	354	469	422	0.482	1,585	1,390	4.3%
	A3	10:13	6.9%	458	370	1	371	534	422	0.505	1,589	1,405	3.9%
	A4	10:15	6.5%	629	352	1	353	517	421	0.480	1,644	1,417	3.6%
	B1	10:02	4.2%	2,038	328	1	330	481	422	0.449	1,601	1,402	3.9%
	B2	10:04	6.4%	750	367	1	368	544	423	0.501	1,603	1,405	3.9%
	B3	10:06	5.6%	1,173	355	1	356	507	422	0.484	1,590	1,391	4.3%
	B4	10:07	5.0%	1,375	345	1	346	482	421	0.471	1,591	1,400	4.1%
	C1	9:54	6.8%	874	413	1	414	581	420	0.563	1,552	1,367	4.9%
	C2	9:56	5.5%	1,374	377	1	378	497	415	0.514	1,572	1,387	4.8%
	C3	9:58	4.8%	1,621	355	1	356	475	408	0.484	1,560	1,397	4.6%
	C4	10:00	3.9%	3,598	325	1	326	380	406	0.444	1,605	1,410	3.9%
	D1	9:46	5.3%	2,125	364	1	365	403	407	0.497	1,598	1,388	4.3%
	D2	9:48	5.9%	3,130	375	1	376	455	404	0.512	1,585	1,385	4.5%
	D3	9:50	4.7%	3,361	350	1	351	501	402	0.478	1,586	1,364	4.6%
Left	D4	9:52	3.6%	4,000	341	1	342	492	399	0.465	1,574	1,364	4.7%
		AVG	5.41%	1,814	356	1	357	487	414.7	0.486	1,589	1,392	4.27%
		AVG A	6.20%	901	350	1	351	500	421.5	0.478	1,603	1,405	3.95%
		AVG B	5.30%	1,334	349	1	350	504	422.0	0.476	1,596	1,400	4.05%
		AVG C	5.25%	1,867	368	1	369	483	412.3	0.501	1,572	1,390	4.55%
		AVG D	4.88%	3,154	358	1	359	463	403.0	0.488	1,586	1,375	4.53%
		AVG 2&3	5.85%	1,568	363	1	364	498	415	0.495	1,584	1,391	4.36%

Spray Dry Absorber
Inlet

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Static Press. " H_2O	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 11													
03/11/1999													
Static Pr=	9:47	1	6.1	2,591	269	280	325.1	0.4423	-3.60	0.24	0.4899	32.46	26,184
-3.97	9:49	2	6.6	2,270	271	283	338.9	0.4611	-4.20	0.27	0.5196	34.50	27,828
Duct SF=	9:51	3	6.8	1,492	275	283	348.8	0.4746	-4.70	0.29	0.5385	35.75	28,841
13.444444	9:53	4	6.8	1,378	282	282	357.7	0.4866	-4.40	0.32	0.5657	37.53	30,275
	9:55	5	6.7	1,366	286	282	360.2	0.4901	-4.50	0.24	0.4899	32.50	26,219
Baro. Pr=	9:56	6	7.1	1,111	286	283	370.6	0.5042	-4.50	0.28	0.5292	35.13	28,339
29.96	9:59	7	7.6	896	270	283	363.0	0.4938	-4.30	0.29	0.5385	35.75	28,841
	10:01	8	6.9	864	279	284	356.4	0.4849	-4.00	0.29	0.5385	35.78	28,860
	10:02	9	6.1	2,244	282	283	340.8	0.4637	-3.30	0.39	0.6245	41.46	33,445
	10:04	10	6.2	2,246	282	283	343.1	0.4669	-3.40	0.43	0.6557	43.54	35,119
	10:07	11	6.6	1,765	279	283	348.9	0.4748	-4.00	0.39	0.6245	41.46	33,445
	10:08	12	6.2	1,955	285	283	346.8	0.4718	-3.90	0.31	0.5568	36.96	29,818
	10:10	13	6.4	1,886	276	284	340.5	0.4632	-3.40	0.39	0.6245	41.49	33,468
	10:11	14	6.5	1,720	278	284	345.3	0.4698	-3.90	0.41	0.6403	42.54	34,315
	10:14	15	6.7	2,121	268	283	337.5	0.4592	-3.60	0.39	0.6245	41.46	33,445
	10:15	16	6.3	2,106	275	283	336.9	0.4584	-3.80	0.35	0.5916	39.28	31,684
		Ave.	**6.60**	**1,751**	**278**	**282.9**	**347.5**	**0.4728**	**-3.97**		**0.5720**	**37.97**	**30,633**

Malmstrom AFB Generator No. 1
March 11, 1999 Tests
Test Run No. 12

CONTROL SCREENS

		11:30	11:45	12:00	Average
Outside Air Temp	TI720	39	40	41	40.0
Supply Pressure	PI416A	321.45	319.57	318.27	319.76
Return Pressure	PI416B	279.80	278.24	276.93	278.32
System	TI413	306.28	305.95	306.78	306.34
Load Zone 1	QI417	2.72	2.59	2.95	2.75
Zone 1 Temperature	TI414	283.82	284.99	286.16	284.99
Zone 1 Flow Rate	FI417	840.01	844.75	853.56	846.11
Load Zone 2-Plant	QI418	4.99	4.61	5.31	4.97
Temp-Zone 2 Plant Return	TI415	290.48	289.13	289.39	289.67
Zone 2 and Plant Ret	FI418	1,639.15	1,597.61	1,582.82	1,606.53
HTWG System Pressure	PIC407	274.11	272.77	271.57	272.82
HTWG 1 Btu Output	QI117	29.76	29.27	30.57	29.87
HTWG 1 Inlet Temp	TI112	295.20	294.61	295.62	295.14
HTWG 1 Outlet Temp	TI111	337.52	337.09	338.27	337.63
HTWG 1 Water Flow	FI108	1,653.91	1,634.11	1,655.06	1,647.69
HTWG 1 Flue Gas Temp	TI114	345.34	343.22	342.69	343.75
SDA 1 Inlet Temp	TI710	247.49	241.96	238.61	242.69
Baghouse 1 Inlet	TI115	192.61	199.98	192.86	195.15
Baghouse 1 Outlet	TI149	197.98	197.11	196.73	197.27
Total Load	QI419	7.74	7.13	8.21	7.69
D A Tank Temp	TI207	193	194	194	193.7
Combustion Air Temp	TI725	67	68	68	67.7
SDA 3 Slurry Flow	FI734				
Baghouse 1 Pressure	PDI105	1.00	1.00	1.02	1.01
Slaked Lime Storage	LIC775	8.59	8.58	8.58	8.58
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101				
Extank Level	LI409	201.64	200.78	200.00	200.81
HTWG 1 Coal Feeder	HSC112A	52.54	52.54	53.38	52.82
HTWG 1 O_2 Trim Control	AIC102				
MBtu Modified	QI118	27	28	29	28.00

Generator No.1 Collector Outlet/Air Heater Inlet
March 11, 1999 Run 12

CO, NO, NO_2, NOx, & SO_2 corrected to 3% O_2

		Time	Oxygen % Dry	3% O_2 CO ppm	3% O_2 NO ppm	3% O_2 NO_2 ppm	3% O_2 NOx ppm	3% O_2 SO_2 ppm	Flue Gas Temp. °F	3% O_2 NOx lb/MMBtu	Port D Left Furnace Outlet Temp. °F	Port A Right Furnace Outlet Temp. °F	Plant Rosemont Oxygen % Wet
Right	A1	11:56	7.3%	103	294	1	295	546	344	0.401	1,181	1,175	6.3%
	A2	11:58	7.2%	121	297	1	298	533	345	0.405	1,185	1,177	6.4%
	A3	12:00	6.7%	157	281	1	283	556	345	0.385	1,197	1,184	5.9%
	A4								345		1,184	1,185	6.3%
	B1	11:49	7.8%	111	300	1	301	576	346	0.410	1,182	1,185	6.3%
	B2	11:51	7.3%	114	298	1	299	579	345	0.407	1,180	1,177	6.3%
	B3	11:53	7.3%	111	289	1	290	571	348	0.395	1,178	1,185	6.2%
	B4	11:55	7.5%	117	292	1	293	566	345	0.399	1,174	1,178	6.3%
	C1	11:41	7.5%	162	300	1	301	581	342	0.410	1,162	1,173	6.2%
	C2	11:42	7.1%	126	297	1	299	567	341	0.407	1,175	1,152	6.5%
	C3	11:44	7.4%	150	296	1	297	594	339	0.404	1,165	1,170	6.3%
	C4	11:47	7.3%	124	286	1	287	574	339	0.390	1,170	1,181	6.1%
	D1	11:34	6.8%	172	289	1	290	567	342	0.395	1,171	1,196	6.3%
	D2	11:35	7.0%	140	294	1	295	666	340	0.401	1,169	1,167	6.5%
	D3	11:37	7.8%	132	301	1	302	661	339	0.411	1,163	1,167	6.3%
Left	D4	11:39	7.5%	140	294	1	296	609	338	0.403	1,162	1,160	6.4%
		AVG	7.30%	132	294	1	295	583	342.7	0.401	1,175	1,176	6.29%
		AVG A	7.07%	127	291	1	292	545	344.8	0.397	1,187	1,180	6.23%
		AVG B	7.48%	113	295	1	296	573	346.0	0.402	1,179	1,181	6.28%
		AVG C	7.33%	141	295	1	296	579	340.3	0.403	1,168	1,169	6.28%
		AVG D	7.28%	146	295	1	296	626	339.8	0.402	1,166	1,173	6.38%
		AVG 2&3	7.23%	131	294	1	295	591	343	0.402	1,177	1,172	6.30%

Spray Dry Absorber
Inlet

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Static Press. " H_2O	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 12													
03/11/1999	11:30	1	8.7	139	220	241	322.3	0.4385	-1.20	0.08	0.2828	18.18	14,664
Static Pr=	11:32	2	8.6	107	223	241	324.0	0.4409	-1.10	0.08	0.2828	18.18	14,664
-1.23	11:34	3	8.5	109	227	241	327.2	0.4452	-1.20	0.08	0.2828	18.18	14,664
Duct SF=	11:35	4	8.3	123	226	240	320.6	0.4362	-1.20	0.09	0.3000	19.27	15,542
13.444444	11:37	5	8.6	124	227	240	329.8	0.4488	-1.20	0.08	0.2828	18.17	14,653
	11:39	6	8.5	127	223	238	321.4	0.4373	-1.20	0.09	0.3000	19.24	15,520
	11:40	7	8.4	124	231	239	330.3	0.4494	-1.20	0.09	0.3000	19.25	15,531
	11:41	8	8.4	138	234	239	334.6	0.4552	-1.20	0.09	0.3000	19.25	15,531
	11:43	9	8.5	120	234	239	337.3	0.4589	-1.20	0.11	0.3317	21.29	17,170
	11:45	10	8.4	118	238	239	340.3	0.4630	-1.30	0.11	0.3317	21.29	17,170
	11:47	11	8.3	138	234	237	332.0	0.4516	-1.20	0.10	0.3162	20.27	16,348
	11:48	12	7.9	156	238	238	327.3	0.4453	-1.30	0.10	0.3162	20.28	16,359
	11:50	13	8.3	150	238	238	337.6	0.4594	-1.30	0.10	0.3162	20.28	16,359
	11:51	14	8.4	132	238	238	340.3	0.4630	-1.30	0.10	0.3162	20.28	16,359
	11:54	15	8.3	138	239	236	339.1	0.4613	-1.30	0.10	0.3162	20.25	16,336
	11:55	16	8.3	131	238	237	337.6	0.4594	-1.30	0.10	0.3162	20.27	16,348
		Ave.	**8.40**	**130**	**232**	**238.8**	**331.4**	**0.4508**	**-1.23**		**0.3058**	**19.62**	**15,826**

Malmstrom AFB Generator No. 1
March 11, 1999 Tests
Test Run No. 13

CONTROL SCREENS

		13:15	13:30	13:45	Average
Outside Air Temp	TI720	40	39	40	39.7
Supply Pressure	PI416A	306.94	304.15	301.38	304.16
Return Pressure	PI416B	265.65	263.06	260.19	262.97
System	TI413	300.11	299.27	299.19	299.52
Load Zone 1	QI417	0.24	0.19	0.20	0.21
Zone 1 Temperature	TI414	284.75	283.90	282.65	283.77
Zone 1 Flow Rate	FI417	850.05	854.62	852.98	852.55
Load Zone 2-Plant	QI418	0.15	0.00	0.00	0.05
Temp-Zone 2 Plant Return	TI415	288.89	288.88	287.80	288.52
Zone 2 and Plant Ret	FI418	1,614.36	1,603.91	1,621.98	1,613.42
HTWG System Pressure	PIC407	261.09	258.55	256.16	258.60
HTWG 1 Btu Output	QI117	19.18	18.82	18.71	18.90
HTWG 1 Inlet Temp	TI112	292.11	291.03	290.62	291.25
HTWG 1 Outlet Temp	TI111	324.58	323.56	323.56	323.90
HTWG 1 Water Flow	FI108	1,646.98	1,641.58	1,645.83	1,644.80
HTWG 1 Flue Gas Temp	TI114	329.67	329.47	330.59	329.91
SDA 1 Inlet Temp	TI710	225.84	223.30	221.31	223.48
Baghouse 1 Inlet	TI115	192.37	192.12	191.74	192.08
Baghouse 1 Outlet	TI149	190.74	189.75	188.87	189.79
Total Load	QI419	0.42	0.20	0.19	0.27
D A Tank Temp	TI207	192	192	192	192.0
Combustion Air Temp	TI725	68	68	67	67.7
SDA 3 Slurry Flow	FI734				
Baghouse 1 Pressure	PDI105	0.95	0.99	1.00	0.98
Slaked Lime Storage	LIC775	8.55	8.53	8.55	8.54
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101				
Extank Level	LI409	193.47	191.84	190.21	191.84
HTWG 1 Coal Feeder	HSC112A	39.93	41.61	41.61	41.05
HTWG 1 O_2 Trim Control	AIC102				
MBtu Modified	QI118	13	14	16	14.33

Generator No.1 Collector Outlet/Air Heater Inlet

March 11, 1999 Run 13

CO, NO, NO_2, NOx, & SO_2 corrected to 3% O_2

		Time	Oxygen % Dry	3% O_2 CO ppm	3% O_2 NO ppm	3% O_2 NO_2 ppm	3% O_2 NOx ppm	3% O_2 SO_2 ppm	Flue Gas Temp. °F	3% O_2 NOx lb/MMBtu	Port D Left Furnace Outlet Temp. °F	Port A Right Furnace Outlet Temp. °F	Plant Rosemont Oxygen % Wet
Righ t	A1	13:30	7.2%	196	258	1	259	504	325	0.352	1,122	1,145	6.5%
	A2	13:32	7.3%	208	261	1	262	542	327	0.356	1,134	1,129	6.7%
	A3	13:34	7.1%	207	252	1	253	532	327	0.344	1,136	1,140	6.5%
	A4	13:36	7.6%	197	264	1	265	544	327	0.361	1,127	1,146	6.3%
	B1	13:23	8.5%	192	282	1	283	542	327	0.385	1,091	1,118	7.2%
	B2	13:25	7.8%	205	270	1	271	519	328	0.369	1,110	1,139	6.6%
	B3	13:27	7.7%	234	257	1	258	537	328	0.351	1,128	1,142	6.5%
	B4	13:28	7.9%	237	259	1	261	553	328	0.355	1,117	1,139	6.6%
	C1	13:15	7.7%	235	255	1	257	553	325	0.350	1,104	1,133	6.5%
	C2	13:16	7.5%	260	254	1	256	564	326	0.348	1,085	1,122	7.1%
	C3	13:18	7.9%	178	272	1	273	557	325	0.371	1,086	1,115	7.1%
	C4	13:20	8.6%	188	285	1	287	571	325	0.390	1,082	1,104	7.4%
	D1	13:07	6.1%	419	215	1	216	502	322	0.294	1,161	1,166	5.5%
	D2	13:09	6.7%	453	230	1	231	513	323	0.314	1,146	1,174	5.9%
	D3	13:11	7.1%	281	248	1	249	615	323	0.339	1,122	1,133	6.6%
Left	D4	13:13	7.7%	228	261	1	262	604	323	0.356	1,103	1,135	6.6%
		AVG	7.53%	245	258	1	259	547	325.6	0.352	1,116	1,136	6.60%
		AVG A	7.30%	202	259	1	260	531	326.5	0.353	1,130	1,140	6.50%
		AVG B	7.98%	217	267	1	268	538	327.8	0.365	1,112	1,135	6.73%
		AVG C	7.93%	215	267	1	268	561	325.3	0.365	1,089	1,119	7.03%
		AVG D	6.90%	345	239	1	240	559	322.8	0.326	1,133	1,152	6.15%
		AVG 2&3	7.39%	253	256	1	257	547	326	0.349	1,118	1,137	6.63%

Spray Dry Absorber
Inlet

Run 13	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O_2	NOx lb/MMBtu	Static Press. " H_2O	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
03/11/1999	13:09	1	10.0	257	168	220	275.3	0.3746	-1.00	0.05	0.2236	14.15	11,416
Static Pr=	13:10	2	9.4	252	175	223	271.9	0.3699	-1.00	0.05	0.2236	14.18	11,441
-1.08	13:12	3	9.5	233	180	223	282.1	0.3838	-1.10	0.05	0.2236	14.18	11,441
Duct SF=	13:13	4	10.1	178	180	223	297.7	0.4050	-1.10	0.06	0.2449	15.54	12,533
13.444444	13:15	5	10.2	158	184	223	307.1	0.4179	-1.00	0.06	0.2449	15.54	12,533
	13:17	6	10.4	167	180	221	306.1	0.4165	-1.10	0.06	0.2449	15.51	12,514
	13:18	7	10.1	170	184	222	304.3	0.4140	-1.10	0.06	0.2449	15.53	12,524
	13:20	8	10.6	136	192	222	332.8	0.4529	-1.10	0.05	0.2236	14.17	11,432
	13:21	9	10.5	138	192	222	329.7	0.4485	-1.10	0.07	0.2646	16.77	13,527
	13:23	10	10.6	138	196	221	339.8	0.4623	-1.10	0.07	0.2646	16.76	13,517
	13:25	11	10.4	171	200	222	340.2	0.4628	-1.10	0.07	0.2646	16.77	13,527
	13:26	12	10.2	173	199	222	332.2	0.4519	-1.10	0.06	0.2449	15.53	12,524
	13:28	13	9.7	195	195	222	311.0	0.4232	-1.10	0.06	0.2449	15.53	12,524
	13:30	14	10.0	204	184	220	301.5	0.4102	-1.10	0.07	0.2646	16.74	13,507
	13:31	15	9.7	188	191	221	304.7	0.4145	-1.10	0.07	0.2646	16.76	13,517
	13:33	16	9.6	198	195	222	308.3	0.4194	-1.10	0.06	0.2449	15.53	12,524
		Ave.	**10.06**	**185**	**187**	**221.8**	**309.0**	**0.4205**	**-1.08**		**0.2457**	**15.57**	**12,562**

Malmstrom AFB Generator No. 1
March 11, 1999 Tests
Test Run No. 14

CONTROL SCREENS

		14:45	15:00	15:15	Average
Outside Air Temp	TI720	41	41	41	41.0
Supply Pressure	PI416A	300.86	302.27	302.84	301.99
Return Pressure	PI416B	260.19	261.70	262.87	261.59
System	TI413	312.37	311.70	311.87	311.98
Load Zone 1	QI417	5.25	5.04	5.11	5.13
Zone 1 Temperature	TI414	278.04	279.38	279.71	279.04
Zone 1 Flow Rate	FI417	850.05	851.81	856.48	852.78
Load Zone 2-Plant	QI418	9.69	9.16	9.27	9.37
Temp-Zone 2 Plant Return	TI415	288.39	287.88	287.72	288.00
Zone 2 and Plant Ret	FI418	1,601.82	1,617.13	1,619.21	1,612.72
HTWG System Pressure	PIC407	255.86	257.20	258.25	257.10
HTWG 1 Btu Output	QI117	44.46	42.44	43.44	43.45
HTWG 1 Inlet Temp	TI112	296.87	296.11	296.62	296.53
HTWG 1 Outlet Temp	TI111	356.02	354.25	354.52	354.93
HTWG 1 Water Flow	FI108	1,641.77	1,664.43	1,659.08	1,655.09
HTWG 1 Flue Gas Temp	TI114	382.41	381.02	361.76	375.06
SDA 1 Inlet Temp	TI710	250.38	252.27	248.79	250.48
Baghouse 1 Inlet	TI115	202.59	198.10	191.49	197.39
Baghouse 1 Outlet	TI149	196.61	195.23	195.98	195.94
Total Load	QI419	14.96	14.21	14.34	14.50
D A Tank Temp	TI207	191	191	191	191.0
Combustion Air Temp	TI725	67	68	68	67.7
SDA 3 Slurry Flow	FI734				
Baghouse 1 Pressure	PDI105	1.83	1.77	1.60	1.73
Slaked Lime Storage	LIC775	8.53	8.53	8.50	8.52
HTWG 1 SO_2 Removal	AI713	2.00	2.00	2.00	2.00
HTWG 1 Stack Opacity	AI101				
Extank Level	LI409	189.35	190.29	191.15	190.26
HTWG 1 Coal Feeder	HSC112A	65.12	65.12	68.06	66.10
HTWG 1 O_2 Trim Control	AIC102				
MBtu Modified	QI118	44	42	33	39.67

Generator No.1 Collector Outlet/Air Heater Inlet
March 11, 1999 Run 14

CO, NO, NO_2, NOx, & SO_2 corrected to 3% O_2

		Time	Oxygen % Dry	3% O_2 CO ppm	3% O_2 NO ppm	3% O_2 NO_2 ppm	3% O_2 NOx ppm	3% O_2 SO_2 ppm	Flue Gas Temp. °F	3% O_2 NOx lb/MMBtu	Port D Left Furnace Outlet Temp. °F	Port A Right Furnace Outlet Temp. °F	Plant Rosemont Oxygen % Wet
Right	A1	14:41	5.9%	116	319	1	320	485	364	0.435	1,346	1,317	5.7%
	A2	14:43	5.4%	373	313	1	315	428	365	0.429	1,353	1,314	5.6%
	A3	14:45	5.7%	323	322	1	323	530	364	0.439	1,329	1,317	5.7%
	A4	14:47	5.6%	209	321	0	321	637	364	0.437	1,338	1,315	5.7%
	B1	14:49	6.7%	86	336	1	337	562	369	0.459	1,340	1,304	6.0%
	B2	14:51	6.4%	161	334	1	335	510	370	0.456	1,349	1,307	5.9%
	B3	14:53	5.4%	201	316	1	317	485	366	0.431	1,351	1,321	5.9%
	B4	14:55	5.6%	148	319	1	320	507	364	0.435	1,321	1,290	6.1%
	C1	14:58	7.9%	30	351	1	353	526	375	0.480	1,318	1,295	5.8%
	C2	15:00	7.1%	63	322	1	322	477	374	0.438	1,318	1,294	5.8%
	C3	15:02	6.4%	65	321	1	322	465	371	0.438	1,337	1,308	5.2%
	C4	15:04	6.6%	56	325	1	326	507	370	0.444	1,316	1,288	5.8%
	D1	15:07	5.4%	50	262	1	263	470	368	0.358	1,412	1,362	3.7%
	D2	15:09	5.3%	241	253	1	254	502	368	0.346	1,446	1,388	3.2%
	D3	15:11	4.9%	310	237	1	238	474	366	0.324	1,441	1,395	3.1%
Left	D4	15:13	4.0%	842	225	0	225	531	365	0.306	1,466	1,405	3.2%
		AVG	5.89%	205	305	1	306	506	367.7	0.416	1,361	1,326	5.15%
		AVG A	5.65%	255	319	1	320	520	364.3	0.435	1,342	1,316	5.68%
		AVG B	6.03%	149	326	1	327	516	367.3	0.445	1,340	1,306	5.98%
		AVG C	7.00%	54	330	1	331	494	372.5	0.450	1,322	1,296	5.65%
		AVG D	4.90%	361	244	1	245	494	366.8	0.333	1,441	1,388	3.30%
		AVG 2&3	5.83%	217	302	1	303	484	368	0.413	1,366	1,331	5.05%

Spray Dry Absorber
Inlet

	Time		Oxygen % dry	CO ppm	NOx	Flue Gas Temp. °F	NOx ppm Corrected to 3% O2	NOx lb/MMBtu	Static Press. " H_2O	Vel. Press. inches H_2O	SQRT Vel. Press.	Vel. fps	Gas Flow afcm
Run 14													
03/11/1999	14:43	1	8.5	124	263	251	379.1	0.5158	-2.40	0.10	0.3162	20.46	16,508
Static Pr=	14:45	2	7.8	130	274	252	373.9	0.5088	-2.30	0.10	0.3162	20.48	16,520
-2.31	14:46	3	7.7	161	278	253	376.5	0.5123	-2.30	0.10	0.3162	20.49	16,531
Duct SF=	14:48	4	7.7	150	278	253	376.5	0.5123	-2.40	0.11	0.3317	21.49	17,338
13.444444	14:50	5	8.0	110	274	253	379.7	0.5166	-2.30	0.09	0.3000	19.44	15,683
	14:51	6	7.8	101	282	253	384.9	0.5236	-2.40	0.09	0.3000	19.44	15,683
	14:53	7	7.9	105	282	254	387.8	0.5276	-2.40	0.09	0.3000	19.46	15,694
	14:54	8	7.7	167	282	254	382.0	0.5197	-2.50	0.10	0.3162	20.51	16,543
	14:56	9	8.0	101	278	254	385.3	0.5242	-2.40	0.13	0.3606	23.38	18,862
	14:58	10	8.0	89	285	254	395.0	0.5374	-2.40	0.13	0.3606	23.38	18,862
	14:59	11	7.9	115	282	254	387.8	0.5276	-2.40	0.12	0.3464	22.47	18,122
	15:01	12	7.9	95	278	254	382.3	0.5201	-2.30	0.11	0.3317	21.51	17,350
	15:03	13	7.8	130	270	251	368.5	0.5013	-2.10	0.13	0.3606	23.33	18,822
	15:04	14	7.2	132	282	252	368.1	0.5008	-2.30	0.13	0.3606	23.35	18,835
	15:06	15	7.7	141	275	252	372.5	0.5068	-2.30	0.13	0.3606	23.35	18,835
	15:07	16	7.2	168	258	250	336.8	0.4582	-1.70	0.12	0.3464	22.40	18,071
		Ave.	**7.80**	**126**	**276**	**252.8**	**377.3**	**0.5133**	**-2.31**		**0.3327**	**21.56**	**17,391**

Appendix B: Stack Test Protocol

1. Pretest Information Gathering and Calculations

   a. Coal

      i. Analysis

      ii. Proximate analysis

         (1) Ultimate analysis from coal supplier

         (2) Fuel curve or computer program to calculate efficiency

   b. Generator

      i. Heat output by Btu/Hour meter

         (1) Inputs to Btu/Hour meter

            (a) Water temperature into generator

            (b) Water temperature out of generator

            (c) Mass flow; office flow element at inlet water temperature and water density

      ii. Heat output by coal feed

         (1) Pounds per hour coal feed from coal scale

         (2) Heat input
            = (Heat value coal as received Btu/#) x (Coal scale #/Hour)
            = Btu/Hour

(3) Generator efficiency

(a) Flue gas oxygen at generator outlet

(b) Flue gas temperature at air heater outlet

(c) Combustion efficiency from fuel curve or computer program

(d) Carbon loss - ABMA curve

(e) Radiation loss - ASME curve

(f) Net efficiency = combustion efficiency - carbon loss - radiation loss

(4) Heat output = (Heat input, Item b.) X (Net efficiency, Item c.) This is the most accurate heat output for the generator.

iii. Wet Flue Gas Flow

(1) Measure the coal input in #/Hour

(2) Fuel curve; for every pound of coal, a quantity of wet flue gas is generated at a specific oxygen content in the flue gas

(3) Flue gas density of coal combustion is:

$$\frac{530(0.078\,\#/cu\,ft)}{460 + Flue\,Gas\,Temperature}$$

(4) Wet flue gas flow = (Coal in #/Hour) (Wet Gas #/# Coal)
= Mass flue gas flow per hour

(5) ACFM:

$$\frac{(Wet\,Mass\,Flue\,Gas}{60\,\mathrm{min}/hr)\,x\,(Density)} = Actual\,cu\,ft/\mathrm{min}$$

(6) Compare this calculated ACFM to field test ACFM at spray dryer inlet. The deviation should be less than 10%.

iv. Calibration By Plant

(1) Coal scale

(2) Water flow meter to generator to be tested

(3) Oxygen analyzer, wet oxygen on fuel curve

(4) Flue gas temperature devices

(5) Slaked lime strength to head tank about 15%

(6) Control valve to spray dryer

(7) Spray dryer outlet temperature - 180 °F

(8) Coal combustion

(a) Even distribution on grates

(b) Fire off rear wall 6 in. to 12 in.

(c) Oxygen in flue gas reasonable for load

(d) Ash discharge off grate front deep

(i) 5 in. light load

(ii) 6 in. to 7 in. average load

(iii) 8 in. high load

2. Test Information

a. Coal

i. Coal feed rate — record integrator readings at beginning and end of each test run

ii. Coal sample during each run of stack test run, 3# sample removed from coal feeder every 10 minutes to make one composite sample per stack test run

iii. Coal analysis - Commercial Testing & Engineering Company or equal

(1) Proximate

(2) Ultimate

(3) Mineral analysis of ash in coal plus lead

(4) Ash fusion temperatures, reducing condition

(5) Free swell index

iv. Coal sizing to each feeder for sample from feeder pokehole plate, check before each test run

b. HTHW Generator System

i. Grate speed - Record at beginning and end of each test run

ii. Ash bed thickness at front of grate - record at beginning and end of each test run

iii. Temperatures

(1) Water in - print (Screen A) every 5 minutes

(2) Water out - print (Screen A) every 5 minutes

(3) Combustion air to air heater - portable instrumentation every 10 minutes

(4) Flue gas from generator - print (Screen C) every 5 minutes and portable instrumentation every 10 minutes

(5) Flue gas at air heater outlet - portable instrumentation every 10 minutes

(6) Flue gas at SDA inlet - print (Screen C) every 5 minutes and portable instrumentation every 10 minutes

(7) Flue gas to baghouse - print (Screen C) every 5 minutes and portable instrumentation every 10 minutes

(8) Flue gas from baghouse - print (Screen C) every 5 minutes and portable instrumentation every 10 minutes

iv. Oxygen

(1) Generator outlet - print (Screen A) every 5 minutes and portable instrumentation every 10 minutes

(2) Mechanical dust collector outlet - portable instrumentation every 10 minutes

(3) Air heater flue gas outlet - portable instrumentation every 10 minutes

(4) SDA inlet - portable instrumentation every 10 minutes

(5) Baghouse inlet - portable instrumentation every 10 minutes

(6) Baghouse outlet - portable instrumentation every 10 minutes

v. Static Pressures

(1) Forced draft fan

(a) Fan discharge - print (Screen C) every 5 minutes

(b) Combustion air - print (Screen C) every 5 minutes

(c) Undergrate air - print (Screen C) every 5 minutes

(2) Over-fire air

(a) Main header - print (Screen A) every 5 minutes and portable instrumentation at beginning and end of each test run

(b) Front upper header - portable instrumentation at beginning and end of each test run

(c) Front lower header - portable instrumentation at beginning and end of each test run

(d) Rear upper header - portable instrumentation at beginning and end of each test run

(e) Rear lower header - portable instrumentation at beginning and end of each test run

(f) Rear reinjection header - portable instrumentation at beginning and end of each test run

(3) Furnace pressure - print (Screen A) every 5 minutes

(4) Generator outlet - print (Screen C) every 5 minutes and portable instrumentation every 10 minutes

(5) Mechanical collector outlet - print (Screen C) every 5 minutes and portable instrumentation every 10 minutes

(6) Air heater flue gas outlet - portable instrumentation every 10 minutes

(7) SDA outlet - portable instrumentation every 10 minutes

(8) Baghouse outlet - portable instrumentation every 10 minutes

(9) Baghouse - print (Screen C) every 5 minutes

vi. Btu Output - print (Screen A) every 5 minutes and record Integrator at the beginning and end of each test run

vii. Opacity - print (Screen C) every 5 minutes

viii. HTHW Flow - print (Screen A) every 5 minutes and record Integrator at the beginning and end of each test run

c. SDA System

i. Analysis of lime - at beginning of testing

ii. Slurry percent solids - at beginning of each test run

iii. Slurry flow - print (Screen F) every 5 minutes

iv. Atomizer current, amps - print (Screen F) every 5 minutes

3. Informational or Compliance Testing

a. Prior to starting test, calculate flue gas flow based upon boiler operating efficiency and compare to stack flow. Prior to any stack test, this will be completed. Estimated time - 7:30 a.m. to 8:30 a.m.

b. Sample for SO_2 at SDA inlet.

c. Sample for SO_2, particulate, and NOx at stack.

4. All stack testing and data gathering shall be started and stopped at the same exact (within one minute) time. There will be one designated person in charge of testing in the Control Room with respect to starting and ending times of each run.

	Time	
Run No. 1 Start	___________	End ___________
Run No. 2 Start	___________	End ___________
Run No. 3 Start	___________	End ___________

5. The organization performing the compliance testing at the SDA inlet and stack should have sufficient equipment and spares to perform simultaneous sampling and allow only 20 minutes between test runs.

Appendix C: Cost Calculations for NOx Emission Control Alternatives

Construction Costs

Variable speed drives (2 generators)	$ 457,800
Air heater modifications (2 generators)	$ 319,200
Flue gas monitors (2 generators)	$ 237,000
Total Construction Cost	**$1,014,000**

Operating Cost for Revised Existing Plant

Operating Labor

These calculations assume the following:

Military personnel are not involved in plant.

WL	= Work Leader, Gross Pay	$19.88/hr
WG	= Wage Grade, Gross Pay	$18.07/hr
LWG	= Low Wage Grade, Gross Pay	$13.59/hr

1st Shift, Monday through Saturday	0 % Increase, Sunday +25%
2nd Shift, Monday through Saturday	7 ½% Increase, Sunday +25%
3rd Shift, Monday through Saturday	10% Increase, Sunday + 25%

A. Shift A 1 WL, 1 WG and 1 LWG
B. Shift B 1 WL, 1 WG and 1 LWG
C. Shift C 1 WL, 1 WG and 1 LWG
D. Shift D 1 WL, 1 WG and 1 LWG

Operating labor costs are calculated as follows:

1st Shift week	7 Shifts	week 8-4	+25%	week
6 Shifts	at $19.88 WL	+1 Shift $24.85/hr =		$1,153.04
6 Shifts	at $18.07 WG	+1 Shift $22.59/hr =		1,048.08
6 Shifts	at $13.59 LWG	+1 Shift $16.99/hr =		$788.24
Total 1st Shift				$2,989.36
2nd Shift + 7 ½%		7 Shifts	WL 4-12	
6 Shifts	at $21.37 WL	+ 1 shift $26.71/hr =		$ 1,239.44
6 Shifts	at $19.43 WG	+ 1 Shift $24.28/hr =		1,126.88
6 Shifts	at $14.61 LWG	+ 1 Shift $18.26/hr =		847.36
Total 2nd Shift				$ 3,213.68
3rd Shift + 10%	7 Shifts	12-8		
6 Shifts	at $21.87	+ 1 Shift $27.24/hr =		$ 1,268.48
6 Shifts	at $19.88	+ 1 Shift $24.85/hr =		1,153.04
6 Shifts	at $14.95	+ 1 Shift $18.69/hr =		867.12
Total 3rd Shift				$3,288.64

day Shift	5 days/week		
Chief	40 hr at $23.49/hr	$939.60	
Instrument	32 hr at $18.07/hr =		578.24
Lead Maintenance	32 hr at $18.07/hr =		578.24
Two Maintenance	80 hr at $13.59/hr =		1,087.20
Total day Shift			$3,183.28
Total Weekly Operating Labor			$12,674.96

Labor When Plant Operates

day					
31 Jan 1998	#3	31 days	Coal		744 Hours
28 Feb 1998	#3	28 days	Coal		672 Hours
31 Mar 1998	#3	31 days	Coal		744 Hours
30 Apr 1998	#3	6.3 days	Coal		152 Hours
	#2	23.6 days	Natural Gas	568 Hours	
	#1	23.6 days	Natural Gas	568 Hours	

31 May 1998	#2	28. days	Natural Gas	672 Hours
	#1	6.5 days	Natural Gas	156 Hours
30 Jun 1998		OFF		
31 Jul 1998		OFF		
31 Aug 1998		OFF		
30 Sep 1998		OFF or Pre-Heat System 2 days		

2 Weeks Startup				
31 Oct 1998	#2	31 days	Natural Gas	744 Hours
30 Nov 1998	#2	30 days	Natural Gas	720 Hours
	#1	20.75 days	Natural Gas	498 Hours
31 Dec 1998	#3	28.5 days	Coal	684 Hours
	#2	2.5 days	Natural Gas	60 Hours
	#1	2.5 days	Natural Gas	60 Hours

257 days of Shift ≈ 36.71 weeks ≈ 37 weeks

Total Operating Labor (37 weeks) X ($12,674.96/week) = $468,974.00/Year

Maintenance Labor

1st Shift

WL	4 Men x 40 hr each	at $19.88/hr	$3,180.80
WG	4 Men x 40 hr each	at $18.07/hr	2,891.20
LWG	4 Men x 40 hr each	at $13.59/hr	2,174.40
			$8,246.40

Day Shift

Chief	40 hr at $23.49/hr	$ 939.60
Instrument	40 hr at $18.07/hr	722.80
Lead Maintenance	40 hr at $18.07/hr	722.80
Two Maintenance	80 hr at $13.59/hr	1,087.20
		$ 3,472.40
		$ 11,718.80/week

$$\frac{365 \text{ Days/Year}}{7 \text{ Days/Week}} = 52.142 \text{ Weeks/Year}$$

52.142 weeks/Year - 37 weeks = X 15.143 week

Total Maintenance Labor $177,456.00/Year

Coal Operating Labor		+ $468,974.00
Coal Maintenance Labor		+ 177,456.00
		$646,430.00
Taxes, etc.	+ 34%	219,786.00
Overhead	+ 10%	64,643.00
Total Operating and Maintenance Labor		$930,859.00/Year

Fuel Usage 1998

One option would be to convert a portion of natural gas usage to coal. The generator operational test determined that stable coal combustion is achievable down to 23 MMBtu/hr heat output. The plant typically burns natural gas at lower loads for easier operation. By switching a portion of the natural gas usage to coal, a fuel savings will be realized. Table C1 shows the 1998 fuel usage and the proposed natural gas to coal usage.

April Natural Gas convert 100% to coal

Natural Gas = (24,800 MCF) (1000 CF/MCF) (890 Btu/CF)

Natural Gas = 2.2072 x 106 Btu/Mo

$$\text{Coal} = \frac{2.2072 \times 10^6 \text{ Btu/Mo.}}{(12{,}626 \text{ Btu/Lb.})(2{,}000 \text{ Lbs./Ton})} = 874.07 \text{ Tons}$$

\+ 314.8 Existing Coal

1,188.87 tons Total Coal

May Natural Gas Convert 50% to Coal

Natural Gas = 23,960 MCF

1/2 Natural Gas to Coal = 1/2 (23,960 MCF) = 11,980 MCF

$$\text{Coal} = \frac{(11{,}980 \text{ MCF})(1{,}000 \text{ CF/MCF})(890 \text{ Btu/CF})}{(12{,}626 \text{ Btu/lb})(2{,}000 \text{ lb/ton})}$$

Coal = 422.232 tons ≈ 422.2 tons to Coal

OCT Natural Gas Only Convert 60% to Coal

Natural Gas = 30,010 MCF - (11,980 MCF Natural Gas)

Natural Gas = 18,030 MCF to Coal

$$\text{Coal} = \frac{(18{,}030 \text{ MCF})(1{,}000 \text{ cu ft/MCF})(890 \text{ Btu/cu ft})}{(12{,}626 \text{ Btu/lb})(2{,}000 \text{ lb/ton})}$$

Coal = 635.46 ≈ 635.5 tons to Coal

Table C1. 1998 proposed natural gas to coal fuel change.

	Calendar 1998			Natural Gas		Proposed Natural Gas	
Month	Days	Coal Tons	Hours	MCF	Hr	Coal Tons	MCF
Jan	31	2,138.6	744 (31 days)	0	0	2,138.6 (31 days)	0
Feb	28	1,601	672 (28 days)	0	0	1,601 (28 days)	0
Mar	31	1,918.9	744 (31 days)	0	0	1,918.9 (31 days)	0
Apr	30	314.8	152 (6.333 days)	11,609.7	568	(23.66 days)	
				13,190.3	568	(23.66 days)	
See calculations that follow				24,800	568	(23.66 days)	
						1,188.9 (720 hr/30 days)	0
MAY	31	0	0	19,282.3 (672 hr/28 days)			
				4,677.7 (156 hr/6.5 days)			
				23,960.0 (31 days)			
See calculations that follow						422.22 (372 hr/15.5 days)	11,980 (372 hr/15.5 days)
JUN				0	0	0	0
JUL				0	0	0	0
AUG				0	0	0	0
SEP	(14 days warm up)						
OCT	31	0	0	30,010 (744 hr/31 days)			
See calculations that follow						635.5	11,980
NOV	30	0		11,427.9 (498 hr/20.75 days)			
				25,352.1 (720 hr/30 days)			
				36,780.0 (30 days)			
See calculations that follow						1,296.3	0
DEC	31	1,805.9	684	1,948.3 (60 hr/2.5 days)			
				1,101.3 (60 hr/2.5 days)			
				3,049.6			
See calculations that follow						1,913.4	0
TOTAL						11,114.8 TONS	23,960 MCF

Nov 30 days Convert 100% to Coal

$$\text{Coal} = \frac{(36{,}780\ \text{MCF})\,(1{,}000\ \text{CF/MCF})\,(890\ \text{Btu/CF})}{(12{,}626\ \text{Btu/lb})\,(2{,}000/\text{lb/ton})}$$

Coal = 1,296.3 tons to Coal

Dec Natural Gas Convert 100% to Coal

$$\text{Coal} = \frac{(3{,}049.6\ \text{MCF})\,(1{,}000\ \text{CF/MCF})\,(890\ \text{Btu/CF})}{(12{,}626\ \text{Btu/lb})\,(2{,}000\ \text{lb/ton})}$$

Coal = 1,07.48 tons ≈ 107.5 tons

1,805.9 tons Existing

1,914.3 tons Total Coal

Revised Coal Operation Fuel Cost

Coal	11,114.8 tons x \$69.00/ton =	\$766,921.00
Natural Gas	23,960 MCF x \$4.701/MCF =	112,636.00
Total fuel cost		\$879,557.00/Year

Other Yearly Costs

Ash Hauling and Disposal	\$ 55,521
Material	
Two Stokers, Ash Handling, Coal Handling and Baghouses	\$ 29,975
Other Chemical (H_2O) and Pumps	\$ 73,136
Electrical Power	\$ 57,281

Motors

Coal Average Load

$$\frac{11{,}114.8\ \text{Tons}}{\text{JAN, FEB, MAR, APR, 1/2 MAY, 2/3 OCT, NOV \& DEC}}$$

Jan 31
Feb 28
Mar 31
Apr 30

May	15
Oct	20
Nov	30
Dec	31

216 days $\text{Coal} = \dfrac{11{,}114.8 \text{ Tons}}{216 \text{ Days} \times 24 \text{ Hrs./Day}}$

Coal = 2.144 tons/hr

Coal = 2.144 tons/hr x 2,000 lb/ton x 12,626 Btu/hr

Coal = 54.1417 x 106 Btu/hr

Heat Output = 44.66 x 106 Btu/hr

$$\text{Average Load} = \frac{44.66 \times 10^6 \text{ Btu/Hr.}}{85.0 \times 10^6 \text{ Btu/Hr.}} = 52.55\%$$

$$\textbf{Fans} = \left(\frac{52.55\%}{100.00\%}\right)^2 (\text{HP}) = 0.276\,(\text{HP})$$

Adjust for Excess Air is 30% HP

Coal Motors:

400 HP x 0.30	=	120 BHP	ID Fan
100 HP x 0.30	=	30 BHP	FD Fan
50 HP x 0.30	=	15 BHP	OFA Fan
50 HP x 0.30	=	15 BHP	Spray Dryer
35 HP x 0.20	=	7 BHP	Reverse Air
5 HP x 1.00	=	5 BHP	
		192 BHP	

Coal Handling:

2 Vib Feeder	=	10
Conv.	=	5
Bucket	=	15
Conv.	=	4
Drag	=	20
		70

$$\text{Coal Handling} = \frac{5 \text{ Hrs.}}{7 \text{ days} \times 24 \text{ Hrs.}} = 0.03 \times 70 \text{ BHP} = 2.1 \text{ BHP}$$

Ash Handling $\frac{3\text{ Hrs.}}{24} \times 100 =$ 12.5 BHP

Spray Dryer Slaker 50 KW - (50%) $\frac{32.9\text{ BHP}}{239.5\text{ BHP/Hr.}}$

\$0.06/KWH x 239.5 BHP x 24 hr/day x 216 days/Year x 0.76 KW/HP = \$56,616

Natural Gas Average Load $\frac{23{,}960\text{ MCF}}{1/2\text{ May}, 1/3\text{ OCT}}$

May 16
Oct 11

27 days Gas = $\frac{23{,}960\text{ MCF}}{27\text{ Days} \times 24\text{ Hrs./Day}}$

Gas = 36.975 MCF/hr

= 36.975 MCF/hr x 1,000 CF/MCF x 890 Btu/CF

= 32.908 x 106 Btu/hr

Heat Output = 25.96 x 106 Btu/hr

$$\text{Average Load} = \frac{25.96 \times 10^6\text{ Btu/Hr.}}{30.0 \times 10^6\text{ Btu/Hr.}} = 86.55\%$$

$$\textbf{Fans} = \left(\frac{86.55\%}{100.00\%}\right)^2 (\text{HP}) = 0.749\,(\text{HP})$$

Adjust for Excess Air is 75% HP

Natural Gas Motors

ID (20 HP) (0.75) = 15 BHP
FD (10 HP) (0.75) = 7.5 BHP
22.5 BHP/hr

\$0.06/KW x 22.5 BHP x 24 hr/day x 27 days/yr x 0.76 KW/HP = \$665

Total Motor Power Cost

Coal Motors	\$56,616
Natural Gas Motors	665
Total Electrical Cost	\$57,281/yr

Lime (105 tons @ $85/ton)	$	8,925
Total Other Costs	$	222,447

Total Yearly Costs To Extend Coal-Firing Season

Operating and Maintenance Labor	$ 930,859
Coal and Natural Gas Fuels	$ 879,557
Other Costs	$ 224,838
Total Operating Costs for Revised Existing Plant	$2,035,254/yr

Co-Fire Coal and 10 Percent Natural Gas

10 Percent Natural Gas - Size Burners for 15 Percent MCR

10% x 0.10 lb NOx/MMBtu = 0.01 (natural gas)

90% x 0.45 lb NOx/MMBtu = 0.405 (coal)

Total 0.415 lb NOx/MMBtu

Co-Firing Technology

Co-firing coal and natural gas in stoker boilers has been successfully accomplished at several facilities, including Dover Light & Power, Oberlin College, Hoover Company, and Ford Motor Company. A co-firing system will typically have one or more natural gas burners located in the sidewalls of the stoker. The most advantageous method has been to locate two burners near opposite corners to develop a circular flow pattern. This creates a better mixing zone for combustion. The amount of natural gas co-fired is adjusted to improve particulate emissions, low load performance, efficiency, and cost effectiveness.

Construction Cost

1) One 85 MMBtu/hr heat output HTHW generator - in plant work only.

a) Burners and burner management (Coen)	$	120,000
b) Pressure parts (tubes) for two holes	$	50,000
c) Mount two burners and refractory	$	90,000
d) NFPA-8501, low water cut-outs, grate scanner	$	15,000

e) Combustion control - limit heat input on both coal and natural gas to 103 MMBtu/hr	$ 35,000
f) Gas piping, meter, and regulator	$ 25,000
g) Electrical power and control	$ 25,000
h) Engineering	$ 25,200
i) Contingency	$ 38,500
Total for one generator	$ 423,700
2) One additional 85 MMBtu/hr heat output HTHW generator Construction cost	$ 423,700
3) Gas service piping - existing	$ 0
4) Variable speed drives (two generators)	$ 457,800
5) Air heater modifications	$ 319,200
6) Flue gas monitors	$ 237,000
7) Total Construction Cost	$1,861,400

Operating and Maintenance Labor

Same as revised existing plant $ 930,859

Fuel Costs

Co-firing 10% natural gas with coal

Natural gas for low heat loads = 23,960 MCF

Coal with no co-firing = 11,114.8 tons

Coal with co-firing

90% coal (11,114.8 tons) = 10,003.3 tons

Additional natural gas 10% of coal to natural gas

10% of 11,114.8 tons = 1,111.5 tons

Additional natural gas

$$= \frac{1{,}111.5 \text{ tons/yr} \times 2{,}000 \text{ lb/ton} \times 12{,}626 \text{ Btu/lb}}{890 \text{ Btu/CF} \times 1{,}000 \text{ CF/MCF}}$$

$$= 31{,}536.1 \text{ MCF}$$

Total natural gas

Low heat loads (Spring and Autumn) 23,960 MCF

Co-firing	31,536 MCF
Total gas	55,496 MCF
Cost of natural gas	
55,496 MCF X \$4.70/MCF	\$260,831/Year
Cost of coal	
10,003.3 tons X \$69.00/ton	\$690,228/Year
Total cost of fuel	\$951,059/Year

Other Yearly Costs

Ash Hauling and Disposal	
Existing plant operation less 10%	
\$55,521 x 0.9 =	\$ 49,969
Material	
Two Stokers, Ash Handling, Coal Handling, and Baghouse	\$ 29,975
Other Chemical (H_2O) and Pumps	\$ 73,136

Electrical Power

$$\text{Coal Load} = \frac{44.66\ \text{MMBtu/Hr.} \times 0.9}{85\ \text{MMBtu/Hr.}} = 47.29\%$$

$$\text{Fans} = \left(\frac{47.29\%}{100.00\%}\right)^2 \text{HP} = 0.224\ \text{HP}$$

Adjust for Excess Air is 23%

Existing Coal Motors	239.5 BHP/hr
FD Fan from 30 BHP to 23 BHP	-7.0
OFA Fan from 15 BHP to 11.5 BHP	-3.5
Spray Dryer from 15 BHP to 11.5 BHP	-3.5
Slaker from 32.9 BHP to 29.6 BHP	-3.3
Gas FD Fan	+0.2

222.4 BHP/hr

\$0.06/kWh x 222.4 BHP x 24 hr/day x 216 days/yr x 0.76 kW/HP =	\$52,573
Natural gas motors same as existing	665
Total Electrical Cost	\$53,238

Lime

Existing plant operation less 10%

\$8,925 x 0.9 =	\$ 8,033

Total Yearly Costs for 10 Percent Gas Co-Fire

Operating and Maintenance Labor	\$ 930,859
Coal and Natural Gas Fuels	951,059
Other Costs	214,351
Total Operating Costs for 10% Co-Firing	\$2,096,269/Year

Co-Fire Coal and 20 Percent Natural Gas

20 Percent Natural Gas - Size Burners for 30 Percent MCR

20% x 0.10 lb NOx/MMBtu = 0.02	(natural gas)
80% x 0.45 lb NOx/MMBtu = 0.36	(coal)
Total	0.38 lb NOx/MMBtu

Co-Firing Technology

An example of this technology is used at the Ford Motor Company in a configuration with two sidewall opposed burners per generator.

Construction Cost

1) Same cost as 10% co-firing only increase burner cost \$20,000.

2) Total cost for one unit	\$ 443,700
3) Total cost for second unit	\$ 443,700

4) Gas service piping - existing	$ -0-
5) Variable speed drives (2 generators)	$ 457,800
6) Air Heater Modifications	$ 319,200
7) Flue Gas Monitors	$ 237,000
8) Total Construction Cost	$1,901,400

Operating and Maintenance Labor

Same as revised existing plant	$ 930,859

Fuel Costs

Co-firing 20% natural gas with coal

Natural gas for low heat loads =	23,960 MCF
Coal with no co-firing =	11,114.8 tons
Coal with co-firing	
80% coal (11,114.8 tons) =	8,891.8 tons
Additional natural gas 20% of coal to natural gas	
20% of 11,114.8 tons =	2,223 tons
Additional natural gas =	2,223 tons/yr X 2,000 lb/ton X 12,626 Btu/lb
890 Btu/CF X 1,000 CF/MCF =	63,072.1 MCF
Total natural gas	
Low heat loads (Spring and Autumn) 23,960 MCF	
Co-firing	63,072 MCF
Total gas	87,032 MCF
Cost of natural gas (26%) 87,032 MCF x $4.70/MCF	$ 409,051
Cost of coal (74%) 8,891.8 tons X $69.00/ton	$ 613,534
Total cost of fuel	$1,022,585

Other Yearly Costs

Ash Hauling and Disposal

Existing plant operation less 20%

\$55,521 x 0.8 =	\$ 44,417

Material

Two Stokers, Ash Handling, Coal Handling, and Baghouse	\$ 29,975
Other Chemical (H_2O) and Pumps	\$ 73,136

Electrical Power

$$\text{Coal Load} = \frac{44.66\ \text{MMBtu/hr.} \times 0.8}{85\ \text{MMBtu/hr.}} = 42.03\%$$

$$\text{Fans} = \left(\frac{42.03\%}{100.00\%}\right)^2 \text{HP} = 0.177\ \text{HP}$$

Adjust for Excess Air is 18%

Existing Coal Motors	239.5 BHP/hr
FD Fan from 30 BHP to 18 BHP	-12.0
OFA Fan from 15 BHP to 9 BHP	-6.0
Spray Dryer from 15 BHP to 9 BHP	-6.0
Slaker from 32.9 BHP to 26.3 BHP	-6.6
Gas FD Fan	+1.3
210.2 BHP/hr	

\$0.06/KWH x 210.2 BHP x 24 hr/day x 216 days/yr x 0.76 KW/HP =	\$49,689
Natural gas motors same as existing	665
Total Electrical Cost	\$50,354

Lime

Existing plant operation less 20%

\$8,925 x 0.8 =	\$ 7,140

Total Yearly Costs for 20 Percent Gas Co-Fire

Operating and Maintenance Labor	\$ 930,859

Coal and Natural Gas Fuels	$1,022,585
Other Costs	205,022
Total Operating Costs for 20% Co-Firing	$2,158,466/yr

Add Detroit Stoker OFA System

0.45 lb NOx/MMBtu to 0.405

NOx Reduction Technology

Add third row of over-fire air to 85 MMBtu/hr HTHW generators.

Construction Cost

One unit construction cost.

High pressure over-fire air fan, furnace nozzles from Detroit Stoker	$ 120,000
Field construction including tube bending	$ 200,000
Engineering	$ 25,000
Contingency	$ 37,500
Total for one generator	$ 412,500

One additional 85 MMBtu/hr heat output HTHW generator:

Construction cost	$ 412,500
Variable speed drives (2 generators)	$ 457,800
Air Heater Modifications	$ 319,200
Flue Gas Monitors	$ 237,000
Total Construction Cost	$1,839,000

Operating and Maintenance Labor

The same as revised existing plant	$ 930,859

Fuel Costs

The same as revised existing plant.	$ 879,557

Other Costs

The same as revised existing plant.	$ 224,838

Total Yearly Costs for Detroit Stoker OFA system

The same as revised existing plant.	$2,035,254

Add Detroit Stoker OFA System with FGR and Methane

0.25 to 0.30 lb NOx/MMBtu

NOx Reduction Technology

Add third level of OFA to existing two levels. Add flue gas recirculation and methane (3 percent) to the lowest level of OFA. The upper two levels will have combustion air and will require a new OFA fan. The lower level flue gas recirculation will remove clean flue gas after the ID fan where the static pressure is 0" or near 0" to minimize the fan horsepower.

Construction Cost

Construction cost of one 85 MMBtu/hr heat output generator.

Detroit Stoker material	$ 300,000
Field installation	$ 200,000
Engineering	$ 35,000
Startup cost	$ 30,000
Contingency	$ 50,000
Total for one generator	$ 615,000

One additional 85 MMBtu/hr heat output HTHW generator:

Construction cost	$ 615,000
Gas service piping - use existing	$ -0-
Variable speed drives (2 generators)	$ 457,800
Air Heater Modifications	$ 319,200
Flue Gas Monitors	$ 237,000
Total Construction Cost	$2,344,000

Operating and Maintenance Labor

The same as revised existing plant	$ 930,859

Fuel Costs

Natural gas for low heat loads =	23,960 MCF
Coal with NO methane =	11,114.8 tons
Coal with 3% methane	
97% coal (11,114.8 tons) =	10,781.36 tons
Additional natural gas 3% of coal to natural gas	
3% of 11,114.8 tons =	333.44 tons

Additional natural gas = 333.44tons/yr X 2,000 lb/ton X 12,626 Btu/lb
890 Btu/CF X 1,000 CF/MCF = 9,460.7 MCF

Total natural gas — Low heat loads (spring and autumn)	23,960 MCF
3% methane	9,461 MCF
Total gas	33,421 MCF
Cost of natural gas (33,421 MCF X $4.70/MCF)	$ 157,079
Cost of coal (10,781.36 tons X $69.00/ton)	$ 743.914
Total cost of fuel	$ 900,993

Other Costs

The same as revised existing plant	$ 224,838

Total Yearly Costs for Detroit Stoker OFA with FGR and Methane

Operating and maintenance labor	$ 930,859
Fuel costs	$ 900,993
Other costs	$ 224,838
Total operating costs for Detroit Stoker OFA/FGR/Methane	$2,056,690/yr

Selective Non-Catalytic Reduction Technology

(0.45 lb NOx)(100%-30%) = 0.315 lb NOx/MMBtu

A Fuel Tech NOx OUT process urea injection system should be installed to achieve a 30 percent NOx reduction. The system consists of a storage tank sized to hold approximately 2 weeks of projected urea solution supply, tank heater, control panel with circulation module and control module, electric valve actuators, inline circulation heater, piping, tubing, fittings, pressure gauges, magnetic flowmeter, temperature indicators, tank level controllers, circulation pump, metering pump, water boost pump, injector lances.

Construction Costs

Construction cost of one 85 MMBtu/hr heat output generator.	
Fuel Tech material	$ 750,000
Field installation	$ 350,000
Engineering	$ 70,000
Startup cost	$ 30,000
Contingency	$ 110,000
Total for one generator	$1,310,000
One additional 85 MMBtu/hr heat output generator	
Construction cost	$1,310,000
Variable speed drives (2 generators)	$ 457,800
Air Heater Modifications	$ 319,200
Flue Gas Monitors	$ 237,000
Total Construction Cost	$3,634,000

Operating and Maintenance Labor

The same as revised existing plant	$ 930,859

Fuel Costs

The same as revised existing plant	$ 879,557

Other Costs

Urea solution

50% urea solution at 8GPH/85 MMBtu/hr Heat Output

$$8\text{ GPH} \times 216\text{ hr/yr} \times 24\text{ hr/day} \times \frac{44.66\text{ MMBtu/Hr.}}{85.00\text{ MMBtu/Hr.}} \; \$0.95\text{/Gal} =$$ $20,700

Electrical Power

Fuel Tech System

Pumps	5 BHP x 0.76 KW/BHP =	3.8 KW
Heaters		5.0 KW
		8.8 KW
$0.06/KWH x 24 hr/day x 216 days/yr x 8.8 KW =		$ 2,737
Revised existing plant cost		57,281
Total electrical cost		$ 60,018

Material

Fuel Tech System	$ 2,000
Revised existing plant	29,975
Total Material	$ 31,975

Other costs the same as revised existing plant

Ash hauling and disposal	$ 55,521
Other chemical (H_2O) and pumps	$ 73,136
Lime	$ 8,925
Total other costs	$ 250,275

Total Yearly Costs for Fuel Tech NOx Reduction

Operating and maintenance labor	$ 930,859
Fuel costs	879,557
Other costs	250,275
Total operating costs for fuel tech NOx reduction	$2,060,691

Switch to 100 Percent Natural Gas and No. 2 Fuel Oil

To switch to 100 percent natural gas and No. 2 fuel oil, install natural gas conversion burners in HTWG Nos. 1 and 2. The burners would fire natural gas as a primary fuel and No. 2 fuel oil as backup in the event of a natural gas supply outage. The burners would be guaranteed for NOx emissions of 0.10 lb/MMBtu.

Construction Cost

One 85 MMBtu/hr heat output HTHW generator – in plant work only.

Demolition coal feeders and stoker	$ 10,000
Burners and burner management FD fan (Coen)	$ 170,000
Front wall refractory and new furnace refractory floor	$ 50,000
Mount two burners	$ 50,000
NFPA-8501, low water cut-outs	$ 10,000
Combustion control – modification for No. 2 oil and natural gas	$ 50,000
Gas piping, meter, and regulator	$ 25,000
Oil piping in plant	$ 25,000
Electrical power and control	$ 40,000
Engineering	$ 34,000
Contingency	$ 45,000
Total for One Generator	$ 509,000

One additional 85 MMBtu/hr heat output HTHW generator

Construction Cost	$ 509,000
Gas service piping – commercial gate to plant 1/2 mile	$ 117,000
Oil storage for 5 days	$ 735,000
Total Construction Cost	$1,870,000

Operating and Maintenance Labor

Operating Labor

Same as revised existing plant less the following:

1st Shift	Low Wage Grade	$ 788.24/week
2nd Shift	Low Wage Grade	$ 847.36/week
3rd Shift	Low Wage Grade	$ 867.12/week
Day Shift	Instrument	$ 578.24/week

Day Shift	Two Maintenance	$ 1,087.20/week
		$ 4,168.16/week

$4,168.16/week x 37 weeks = $154,221.92

Coal Operating Labor	$468,974
Less personnel not required for gas	154,222
100 percent natural gas operating labor	$314,752

Maintenance Labor

Same as revised existing plant less the following:

1st Shift	Low Grade	$2,174.40/week
Day Shift	Instrument	$ 722.80/week
Day Shift	Two Maintenance	$1,087.20/week
		$3,984.40/week

$3,984.40/week x 15.143 weeks = $60,335.77

Coal maintenance labor	$177,456
Less personnel not required for gas	- 60,336
100 percent natural gas maintenance labor	$117,120
Gross Wages $431,872	
Taxes, etc. + 34%	146,836
Overhead + 10%	43,187
	$621,895

Fuel Costs

11,114.8 tons — 23,960 MCF

$$\frac{(11{,}114.8\ \text{Ton/Yr.})\ (2{,}000\ \text{Lb./Ton})\ (12{,}626\ \text{Btu/Lb.})}{(1{,}000\ \text{CF/MCF})\ (890\ \text{Btu/CF})} = 315{,}360.6\ \text{MCF/yr}$$

315,360.6 MCF/yr
+ 23,960 MCF/Tr.
339,320.6 MCF
x $ 4.701/MCF

Total Cost of Fuel = $1,595,146.00/yr

Other Costs

Material

Other Chemical (H_2O) and Pumps $ 73,136

Electrical Power

Motors

Average natural gas load

$$\text{Gas} = \frac{339{,}320.6 \text{ MCF/Year}}{243 \text{ Days/Year} \times 24 \text{ Hrs./Day}} = 58.18 \text{ MCF/Hr.}$$

Heat Input = 58.18 MCF/hr x 1,000 CF/MCF x 890 Btu/CF

Heat Input = 51.782 MMBtu/hr

Heat Output = 40.65 MMBtu/hr

$$\text{Average Load} = \frac{40.65 \text{ MMBtu/Hr.}}{85.00 \text{ MMBtu/Hr.}} = 47.82\%$$

$$\text{Fans} = \left(\frac{47.82\%}{100.00\%}\right)^2 (\text{HP}) = 0.229\ (\text{HP})$$

ID Fan 60 HP x 0.23 = 13.8

FD Fan 100 HP x 0.23 = 23.0

36.8 BHP

$0.06/KWH x 36.8 BHP x 24 hr/day x 243 days x 0.76 KW/HP = $9,787

Total Motor Power Cost = $9,787/yr

Total Other Costs = $82,923

Total Yearly Cost for 100 Percent Natural Gas

Operating and Maintenance Labor	$ 621,895
Natural Gas Fuel	$1,595,146
Other Costs	82,923
Total operating cost for 100 percent natural gas	$2,299,964/yr

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John Salley, Charles Schmidt, Martin Savoie, and Eric Johnson

7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)
U.S. Army Construction Engineering Research Laboratory (CERL)
P.O. Box 9005
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13. ABSTRACT *(Maximum 200 words)*

The Malmstrom Air Force Base (MAFB), MT Coal-Fired Heat Plant (CFHP) is designed to fire natural gas or coal. The State of Montana requires that nitrogen oxides (NOx) levels be maintained below the level of 0.50 lb/MMBtu of coal. This study evaluated the Malmstrom AFB CFHP to determine operational and equipment changes to ensure that the CFHP can operate under a wide range of conditions using either coal, or a mix of gas and coal as fuel. Several enhancements were recommended to the CFHP to improve combustion efficiency and air emis-sions, including: improved coal specifications, advanced monitoring systems, combustion air heater modifications, variable speed drives, and operator training.

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